ENERGY REPORT:
Industry Facts and Updates

to the
Regulatory Flexibility Committee

of the
Indiana General Assembly

by the
Indiana Utility Regulatory Commission

September 1999

Chairman William D. McCarty
Commissioner G. Richard Klein
Commissioner David Ziegner
Commissioner Camie Swanson-Hull
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TABLE OF CONTENTS

I. PURPOSE AND SCOPE OF THE REPORT

This report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b). The report outlines the status of competition in the Indiana energy utility industries, both electric and gas. The report reviews the activities of the energy industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 1998 Energy Report.[1] It also examines competition initiatives at the state and federal levels.

II. EXECUTIVE SUMMARY

This Executive Summary, in an effort to remain brief, will not attempt to discuss every item covered in the body of the 1999 Energy Report. Instead, the Executive Summary will highlight new or significant events detailed in the report. The reader is encouraged to review the body of this report or the 1998 Energy Report for items of interest not presented in the Executive Summary.

The Year 2000 Computer Problem (Y2K)

As part of the state and national efforts to address the potential Y2K computer problem the Indiana Utility Regulatory Commission initiated an investigation[2] into the problem as it relates to Indiana utilities' ability to deliver service to their customers. The investigation included electric, gas, telecommunications and water/sewer utilities. It was the Commission's plan to undertake a dual role that would protect the public interest, while addressing the needs of utilities as well.

Since the initiation of the investigation, the IURC has issued and reviewed utility Y2K readiness surveys to assess the utilities' efforts and progress in addressing the Y2K problem. The Commission has also hosted two workshops to facilitate the exchange of information on Y2K readiness.

The IURC continues to monitor the progress Indiana utilities are making toward Y2K compliance. The Commission is committed to do whatever it can to help utilities address any Y2K problems or concerns the utilities may encounter. The Commission is also committed to keeping the public informed on the utilities' progress toward Y2K compliance.

As part of this commitment, the IURC has been actively coordinating its activities with those of State Emergency Management Agency (SEMA). On New Year's Eve and Day, the IURC will

[1] Energy Report, Indiana Utility Regulatory Commission, August 1998.

[2] Cause No. 41327.

have a representative on duty in the SEMA operations room, which will be activated and fully staffed. Additionally, the IURC will have key staff on duty in its offices during the same time period.

Cause No. 41363, IURC Investigation into FAC Proceedings

On January 20, 1999, the IURC issued an order initiating a generic fuel adjustment cost charge ("FAC") investigation.[3] The impetus for the investigation was the escalation in spot market purchase power prices observed in June 1998. The purpose of the generic investigation was to determine whether existing FAC procedures are sufficient to define the appropriate treatments of current wholesale power transactions. The proceeding specifically addressed the following two questions:

On June 2, 1999, an evidentiary hearing was held in the FAC investigation. At this time the FAC investigation is still pending, although an order is expected in the near future.

Electricity Capacity Status for the Summer of 1999

In May 1999, the IURC made an informal inquiry to Indiana's electric utilities to gather information on the electricity capacity status for the summer of 1999.[4] A review of the information provided by the utilities indicated that they had modified their electricity capacity strategies based on their experiences during the summer of 1998. For 1999, Indiana utilities planned maintenance so that it would be completed before the summer peaking season, arranged power purchases to help limit exposure to potentially high spot market prices and spread their purchases among more suppliers to limit possible problems from the default or curtailment of a power supplier.

During July 1999, throughout the Midwest utilities' generation capacity was stretched to its limits due to successive days of temperatures in the mid- and upper-90s and heat indexes over 100. This prompted many utilities in the region, including all of Indiana's electricity-supplying utilities, to request voluntary conservation by the public to help reduce the possibility of rolling blackouts. This situation highlighted the serious decline in generation capacity reserves over the past few years.

Indianapolis Power & Light and several independent power producers have proposed and gained approval for approximately 1700 MW of new generation to be built in Indiana. If completed, this new generation will help improve the capacity margin in Indiana and throughout the region.

[3] Cause No. 41363. The Commission's Investigation of the Treatment of Purchased Power Costs in Summary Fuel Adjustment Clause Proceedings.

[4] IPL, AEP/I&M, PSI, NIPSCO, SIGECO, IMPA, HE and WVPA.

Merchant Power Plant Cases

During the first six months of 1999, the IURC received three petitions regarding "merchant" power plants.[5] The three petitioners were AES Greenfield, Duke Energy Vermillion and Enron Capital and Trade Resources. The IURC approved all three applications. These plants should provide some relief from the capacity problems that Indiana has faced during the past two years and pose no financial risk to consumers.

Merger Approval Authority

From January 1996 to August 1999, the Federal Energy Regulatory Commission approved 25 mergers of electric and gas utilities, with seven mergers pending. This list does not include the recently proposed merger of Carolina Gas & Electric Company and Florida Progress or the proposed merger of SCANA (a holding company in South Carolina) with Public Service Company of North Carolina. This unprecedented wave of mergers, including acquisitions of United States energy utilities by foreign interests and energy marketing firms, creates a number of public policy concerns. The types of concerns range from basic protection of captive customers of the utility to the ability of the merged companies to exercise market power by raising prices and/or reducing service quality. Notwithstanding limited merger review by federal agencies, the scrutiny by federal agencies does not consider the unique interests of individual states.

The IURC's ability to protect captive customers of regulated monopolies from potential adverse consequences of mergers was recently vacated by the Indiana Supreme Court's ruling in the Ameritech – SBC merger case. In this case the Supreme Court held that despite compelling public policy concerns, the General Assembly had not vested merger approval authority in the IURC.

Enforcement Authority

Based on the IURC's experience in the telecommunications industry, there is every reason to believe that our lack of enforcement authority will cause us to face similar problems in the energy industry as competition intensifies. To provide some measure of protection for customers of monopoly utility services, it is necessary for basic enforcement authority to be vested in the Commission.

American Electric Power and Central South West Merger

On December 22, 1997, American Electric Power (AEP) and Central South West Corporation (CSW) announced a stock-for-stock merger transaction which would create a company

[5] Cause Nos. 41361, 41388, 41411.

with a total market capitalization of approximately $28.1 billion and result in the largest electric utility holding company in North American in terms of generating capacity.

On June 29, 1998, the IURC announced an investigation into the merger between AEP and CSW (Cause No. 41210). The IURC also intervened in the three merger-related dockets at the Federal Energy Regulatory Commission.

On April 26, 1999, the Commission approved a settlement agreement between AEP and a Commission negotiating team, In the Matter of the Investigation of the Commission's Own Motion Into Any and All Matters Relating to the Merger of American Electric Power, Inc. and Central and South West Corporation. The IURC agreed not to oppose the merger at the FERC.

The Citizens Action Coalition has appealed the IURC's decision approving the settlement of the merger investigation. There has been no ruling on the appeal. The merger is still pending at the FERC.

Indiana Energy and SIGCORP Merger

Indiana Energy, Inc. (IEI), parent company of Indiana Gas Company Inc., and SIGCORP, parent company of Southern Indiana Gas and Electric Company (SIGECO), have agreed to combine into a new holding company to be named Vectren Corporation. If approved, the tax-free stock-for-stock transaction will create a combined company with a total enterprise value of approximately $1.9 billion. Indiana Energy's and SIGCORP's utility companies will remain separate subsidiaries of Vectren and will continue to operate under their current corporate names. The new company, Vectren, will be based in Evansville, which will also remain home to SIGECO; Indiana Gas will continue to be headquartered in Indianapolis. The merger is conditioned upon the approvals of the shareholders of each company and customary regulatory approvals.

Through its utility subsidiaries, Vectren will offer gas and/or electricity to over 650,000 customers in adjoining service areas that cover nearly two-thirds of Indiana. Indiana Gas serves about 490,000 customers in central Indiana and had revenue of $466 million in 1998. SIGECO serves 233,000 gas and electric customers and reported sales of $557 million in 1998. According to the companies, Vectren's non-utility subsidiaries will offer energy-related products and services, fiber-optic based telecommunications services, and energy marketing to customers throughout the surrounding region.

On June 17, 1999, IEI and SIGCORP filed a joint petition with the Commission requesting approval, to the extent required, of the proposed merger of the two equal companies. Cause No. 41465 is scheduled for hearing on November 9 and 10, 1999.

The Federal Energy Regulatory Commission Notice of Proposed Rulemaking for Regional Transmission Organizations (RTO)

The Indiana Utility Regulatory Commission anticipates filing comments with the Federal Energy Regulatory Commission on its Notice of Proposed Rulemaking (NOPR) for Regional Transmission Organizations.[6] The NOPR recognizes that RTOs have an important role in assuring the reliable supply of electricity and the efficient and fair operation of the wholesale power markets. The NOPR is part of FERC's continuing effort to assure that transmission owners provide compatible, non-discriminatory, open access to transmission facilities to all transmission users.

In the NOPR, the FERC outlined four minimum characteristics: independence, scope and regional configuration, operational authority and short-term reliability and seven minimum functions a RTO must have to meet FERC requirements. The FERC also detailed a policy of Open Architecture for RTO structures. This policy requires that an RTO have a process for modifying or changing the RTO's structure or operation in response to the changing electric industry.

Midwest Independent System Operator (MISO)

On January 15, 1998, the Midwest Independent System Operator (MISO) filed for FERC approval. On September 16, 1998, the FERC gave conditional approval to the MISO filing. In an effort to increase its membership and geographic scope, the MISO has been in discussions with the members of the Alliance RTO, members of the Mid-continent Area Power Pool and members of the Southwest Power Pool.

At their June 1999 meeting, the MISO Board of Directors selected Indiana for their headquarters. The MISO anticipates employing about 150-175 persons with a large percentage of the positions being in highly technical fields. The MISO is in the process of recruiting key executives and expects to be operational in the last half of 2000.

The Alliance RTO Proposal

On June 3, 1999, American Electric Power, Consumers Energy, Detroit Edison, FirstEnergy and Virginia Electric and Power filed a request with the FERC to approve the Alliance Regional Transmission Organization. On July 7, 1999, the IURC filed a protest and a request to intervene at

[6] Docket No. RM99-2-000, issued May 13, 1999.

the FERC. The IURC specifically asked the FERC to employ Alternative Dispute Resolution (ADR) to resolve some issues between the Alliance RTO and other RTOs such as the Midwest ISO. The IURC expressed concern that the Alliance proposal does not fully comply with the eleven independent system operator principles articulated in the FERC's Order 888 and the FERC's Notice of Proposed Rulemaking (RM99-03-000) issued May 13, 1999.

NiSource Unsolicited Offer to Columbia Energy

On April 1, 1999, NiSource, the parent company of Northern Indiana Public Service Company, offered to buy Columbia Energy Group (Columbia), one of nation's largest energy services companies.

NiSource withdrew the offer in anticipation of further merger discussions. On April 16, NiSource renewed its bid after Columbia cancelled the merger discussions. Columbia dismissed the offer. On June 7, NiSource made an unsolicited buyout offer of $68 per share, or $5.7 billion, to Columbia. Columbia continued to refuse to schedule merger talks, and its board unanimously rejected the buyout, saying the company was not for sale.

On June 24, NiSource continued its hostile takeover attempt by appealing to Columbia's shareholders directly by making a tender offer for all of Columbia's outstanding common stock. Columbia advised its shareholders to take no action until the board reviewed the $68 per share offer and made a recommendation. On July 6, Columbia announced that it was once again rejecting NiSource's offer because the offer was inadequate.

NiSource, undeterred by Columbia's rejection, announced July 20, 1999, that with regard to its tender offer of Columbia Energy Group it has filed the necessary information with the Federal Trade Commission and Department of Justice to continue its hostile takeover bid.

State Competition Initiatives in Electricity

Electric utility restructuring continues to be an active issue in many states. New restructuring legislation has recently passed in Ohio, Arkansas, New Jersey and Texas. Consumers in Illinois will begin receiving electricity from alternative suppliers in October 1999. Electric industry restructuring in California has gotten mixed reviews after over a year of retail competition. Appendix 3 presents a summary of restructuring activities by state.

State Competition Initiatives in Natural Gas

The gas industry has been competitive for years at the wholesale and large end-user level, as customers routinely purchase their gas supplies and other load-managing services in the marketplace. Increasingly choice options are also becoming available to residential and small commercial customers.

Federal Legislative Update

During the first six months of 1999, five electricity restructuring bills were introduced into Congress, including an amended comprehensive electricity competition plan from the Clinton administration and the Department of Energy. A comparison chart of all five bills is contained in Appendix 5.

EPA Activity

On October 27, 1998, the U.S. Environmental Protection Agency (EPA) published a final federal rule that requires each of 22 states in the eastern United States, including Indiana, to reduce emissions of nitrogen oxides significantly by 2007.

In May 1999, the Indiana Department of Environmental Management (IDEM) published its rulemaking to implement the EPA rule. Each state had a deadline of September 30, 1999, to develop a NOX reduction plan, or the EPA would impose its own plan to implement the rule. However, numerous parties (many of the 22 states and groups of utilities) have challenged EPA's rule in the District of Columbia U.S. Court of Appeals. In May 1999, in another case, a three- judge panel of this court first ruled that EPA may not have the legal authority to set new Clean Air Act standards for soot and smog. The panel then ruled that the 22 states in the NOX case do not have to meet the September 30, 1999, deadline for filing NOX reduction plans, and a stay of the rule was granted pending the outcome of the case. Oral arguments are expected to take place in the fall of 1999.

Regardless of the outcome of the appeal of the EPA rules, there are existing regulations involving local nonattainment areas for ozone that will need to be addressed in Indiana. IDEM is set to provide a new deadline for comments on its rulemaking at a later date.

III. IURC INVESTIGATION OF YEAR 2000 COMPUTER PROBLEMS

On November 12, 1998, the Indiana Utility Regulatory Commission initiated an investigation[7] into the Year 2000 (Y2K) computer problem as it relates to Indiana utilities' ability

[7] Cause No. 41327.

to deliver service to their customers. The investigation included electric, gas, telecommunications and water/sewer utilities. It was the Commission's plan to undertake a dual role that would protect the public interest and address the needs of utilities. The Commission stated in its order announcing the investigation:

> We believe it is critical that an environment is created where regulators, consumers, industry and consumer groups, and utility providers forge a partnership to work together. This is an issue where all concerned have a vested interest to assist their peers in any way possible. The IURC believes it can best facilitate this process by providing coordinated leadership.

On January 26, 1999, the Commission issued a second order in the Y2K investigation. The order reported the response rates for each utility sector to the IURC's Year 2000 Information Request survey and ordered all investor-owned utilities to submit responses to sector-specific follow-up surveys by February 1, 1999. Finally, the order announced a two-day Y2K workshop, to be held March 2-3, 1999, in Indianapolis, Indiana.

Over 230 participants attended the Y2K workshop on March 2-3, 1999. Many were reassured that other utilities and utility sectors (gas, electric water, sewer and telecommunications) were also diligently addressing the Y2K problem. Information and advice were both formally and informally exchanged and most participants agreed that the workshop had been useful and informative.

On July 13, 1999, the IURC hosted a second Y2K workshop. The workshop focused on contingency planning and public information and education.

The Indiana Utility Regulatory Commission continues to monitor the progress Indiana utilities are making toward Y2K readiness. The Commission is committed to do whatever it can to help utilities address any Y2K problems or concerns the utilities may encounter. The Commission is also committed to keeping the public informed on the utilities' progress toward Y2K readiness.

As part of this commitment, the IURC has been actively coordinating its activities with those of State Emergency Management Agency (SEMA). SEMA, as part of its Y2K awareness program, conducted a series of workshops around the state this summer and the IURC presented information at those workshops. In turn, SEMA personnel attended the IURC Y2K workshop in March and SEMA personnel made presentations during the July workshop. On New Year's Eve and Day, the IURC will have a representative on duty in the SEMA operations room, which will be activated and

B. Recent Developments in Electricity

1. Cause No. 41363, IURC Investigation into FAC Proceedings

On January 20, 1999, the IURC issued an order initiating a generic fuel adjustment cost charge ("FAC") investigation.[8] The impetus for the investigation was the escalation in spot market purchase power prices observed in June 1998. The purpose of the generic investigation was to determine whether existing FAC procedures are sufficient to define the appropriate treatment of current wholesale power transactions.

On March 10, 1999, a docket entry was issued notifying participants that the following two questions would be addressed in the proceeding:

(1) Should the commission set a benchmark for the price of purchased power, which triggers a requirement that the reasonableness of the purchase in excess of the benchmark be specifically addressed in the pre-filed testimony supporting the FAC? If so, what should the benchmark be? What should be included in the supporting pre-filed testimony?

(2) Should the commission require codes of conduct for those generating utilities having marketing affiliates?

On June 2, 1999, an evidentiary hearing was held in the FAC investigation. Witnesses appeared for the Office of Utility Consumer Counselor, the Indiana Industrial Group[9] and the five investor-owned electric utilities.[10] Testimony from Wabash Valley Power Association was stipulated to and accepted into the record.

Proposed orders in the investigation were filed June 16, 1999. At this time the FAC investigation is still pending, although an order is expected in the near future.

2. Merchant Power Plant Cases

During the first six months of 1999, the IURC received three petitions regarding "merchant" power plants.[11] Merchant plants are generating facilities that are constructed to sell electricity into the increasingly competitive wholesale market. The companies that construct merchant plants take the full risk of the cost of construction and operation, which is in contrast to traditionally regulated utilities that build generating facilities with IURC approval and may then recover the cost through the regulated ratemaking process.

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[8] Cause No. 41363. The Commission's Investigation of the Treatment of Purchased Power Costs in Summary Fuel Adjustment Clause Proceedings.

[9] A group of customers that purchase large quantities of electric energy from various utilities in Indiana.

[10] IPL, PSI, AEP/I&M, NIPSCO and SIGECO.

[11] Cause Nos. 41361, 41388, 41411.

The three petitioners, AES Greenfield, Duke Energy Vermillion and Enron Capital and Trade Resources, each requested that the IURC rule that the development companies and the future plant were not public utilities. In the event the Commission did declare that the companies were public utilities, the petitioners asked that the IURC decline jurisdiction over the construction and operation of the power plants.

In the three cases the Commission's orders found that the petitioners were, in fact, public utilities under I.C. 8-1-2-1. However, the petitioners were not exercising any of the rights, powers or privileges of public utilities, such as eminent domain or public rights-of-way, and would not be selling electricity to retail customers or recovering any costs through a rate base. Because of these circumstances, and the expected need for generating capacity within the state, the IURC in large part declined jurisdiction over the petitioners and their construction and operation of the proposed merchant plants. If the petitioners construct any transmission facilities in the future, however, the Commission will re-examine the decision to decline jurisdiction.

The IURC received one additional request regarding new generation construction in the past year. In November 1998, Indianapolis Power and Light filed a petition requesting the Commission decline jurisdiction over the construction and operation of 200 MW of new combustion turbines and approve an alternate regulatory plan regarding jurisdictional use of the plants' output. Alternately, IPL requested that the Commission grant a Certificate of Public Convenience and Necessity for the construction. In April 1999, the Commission approved a settlement agreement between IPL, the Commission staff, the OUCC and other intervening parties that allowed IPL to construct the CTs and defer any determination regarding ratemaking issues to a later proceeding. The agreement also allows IPL to recover fuel costs through the FAC when used for jurisdictional retail purposes. IPL plans to have the CTs in operation by the spring of 2001.

3. The Federal Energy Regulatory Commission Notice of Proposed Rulemaking for Regional Transmission Organizations

The Indiana Utility Regulatory Commission anticipates filing comments with the Federal Energy Regulatory Commission on its Notice of Proposed Rulemaking (NOPR) for Regional Transmission Organizations.[12] A Regional Transmission Organization (RTO) is an organization or institution that controls the transmission system in a particular region and may encompass a variety of organizational structures including independent system operators and transcos. This NOPR is part of FERC's continuing effort to assure compatible, non-discriminatory, open access to transmission facilities.

In the NOPR, the FERC outlined four minimum characteristics:

[12] Docket No. RM99-2-000 issued May 13, 1999.

- Independence: The RTO must be independent of market participants (e.g., generation and transmission owners);
- Scope and Regional Configuration: The RTO must serve an appropriate region to permit the RTO to effectively perform its required functions and to support efficient non-discriminatory power markets;
- Operational Authority: The RTO must have the operational authority for all transmission facilities under its control;
- Short-term Reliability: The RTO must have exclusive authority for maintaining the short-term reliability of the grid.

The NOPR also describes seven minimum functions a Regional Transmission Organization must have to meet FERC requirements. The FERC also details a policy of Open Architecture for RTO structures. This policy requires that an RTO have a process for modifying or changing the RTO's structure or operation in response to the changing electric industry.

If the FERC approves the proposed rules, transmission-owning utilities would have until October 15, 2000, to file RTO proposals. Transmission-owning utilities in currently approved regional transmission organizations would have until January 15, 2001, to file proposals that will bring their transmission organization in line with FERC's minimum characteristics and functions. The Regional Transmission Organizations must be operational by December 15, 2001.

4. Noteworthy 30-Day Filings by Electric Utilities

Thirty-day filings are requests from utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. The 30-day filing process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less-costly manner than a formally docketed case. Last year, the Commission reviewed and approved for the entire utility industry more than 380 of these 30-day filings. Some of the more important electric 30-day filings approved during the last year are summarized here.

Indiana Michigan Power Company

The IURC has approved a series of 30-day filings for Indiana Michigan Power Company (I&M). Two of these were specific pricing options for Tariff Contract Service - Interruptible Power (C.S.-IRP) customers. Under the provisions of Tariff C.S.-IRP, large industrial customers enter into customer-specific contracts with I&M to have portions of their load subject to interruption in exchange for a lower price for electricity. The customers, at the time of an interruption, can either have their service interrupted or "buy through" the interruption if the utility is able to purchase and deliver power from another source.

On January 6, 1999, the IURC approved a 30-day filing, Standard Contract Addendum - Day Ahead Replacement Electricity. When I&M is projecting a capacity deficiency for the next day, customers served under Tariff C.S.-IRP can choose to have the utility arrange to deliver power during a 16-hour period for the next day at an agreed-upon, market-driven price (the utility's cost to purchase on the market and deliver). During periods when the customer's usage is less than the "Day-Ahead Reservation", the customer will receive a credit for unused energy equal to the utility's avoided cost of generation, i.e. the cost the utility avoids by not having to generate that energy.

On April 14, 1999, the IURC approved a second 30-day filing for tariff C.S.-IRP customers, entitled Standard Contract Addendum - Special Pricing Electricity. This Standard Contract Addendum provided another option for these customers to choose to have I&M purchase a block of power at an agreed-upon, market-driven price for one or more time increments ahead of the time interruptions might be expected. These increments are the periods ending June, July and August 1999.

Additionally, Indiana Michigan Power Company has made two 30-day filings for customers who are not tariff C.S.-IRP customers. Both proposals are Riders to existing tariffs QP and IP and the customer must have a minimum on peak curtailable load of 3,000 kVA. The IURC approved on June 23, 1999, a rider entitled ECS - Emergency Curtailable Service. The ECS rider will be included as an additional step in the AEP System Emergency Operating Plan. In exchange for being subject to curtailment under this plan, the customer receives a credit varying from $0.35 per kWh to $0.50 per kWh of load curtailed, depending on the options selected.

On June 16, 1999, I&M filed for approval of a rider entitled PCS - Price Curtailable Service. Rider PCS allows customers to specify a maximum number of days per season they are willing to curtail. Customers may choose from three options for the maximum number of hours per curtailment. The customer also specifies the minimum price for which they are willing to curtail. Rider PCS provides for summer, fall, winter and spring seasons to recognize customer seasonal curtailment abilities and market price variations by season. Payments are based on kWh curtailed by the customer. The price the utility will pay for curtailed energy will be the greater of 80 percent of the daily on-peak into Cinergy index (a regional clearing house or hub for electricity trading); the minimum price as specified by the customer; or 3.5 cents per kWh. The IURC has not yet issued a ruling on the PCS proposal.

The IURC approved on June 9, 1999, the phase-out and discontinuance by September 30, 1999, of the tariff entitled R.S.-VSP Residential Service - Experimental Variable Spot Pricing. The R.S.-VSP program was an experimental data-gathering tariff to test customer responsiveness to time of day pricing. The IURC approved the phase-out and discontinuance of the tariff R.S.-VSP on the basis that it would cost more to make the program Y2K compliant than it was worth. There were 44 customers in Indiana taking service under this tariff.

Indianapolis Power and Light Company

On March 24, 1999, the IURC approved a Standard Contract Rider No. 17, Curtailment Energy, for Indianapolis Power and Light Company (IPL). This rider, available to commercial and industrial customers served under Rates HL, PL, SL, or PH or demand-billed "Elect Plan" (one payment option under IPL's alternative regulatory plan), is available in two options which vary in amount of size of load and payment. In both cases, the customer is provided a payment in exchange for having load curtailed under terms of an agreement.

Northern Indiana Public Service Company

In an expedited approval process, on December 29, 1998, the IURC approved a proposal by Northern Indiana Public Service Company (NIPSCO) relating to charges paid by developers for NIPSCO to install facilities for new residential developments. According to NIPSCO, in recent years some developers had requested the company provide more flexibility with regard to its new residential development procedures. In Cause No. 41291, Stillwater Properties LLC filed a complaint regarding the procedures and, as part of a settlement of that complaint, NIPSCO agreed to offer five options to developers of residential subdivisions. Those options, which are incorporated into the tariff, are:

1) Continuation of NIPSCO's current procedure with the developer paying upfront the estimated expenses, excluding overheads, and the funds returned in accord with the Company's Accounting Bulletin 161.

2) Developer pays prime rate on total amount of estimated expenses, including overheads, at the end of each year for six years. The interest rate will be applied to the remaining balance (estimated expenses minus estimated revenues) at the end of each year. If a balance remains at the end of year six, it will be paid by the developer.

3) Developer provides a satisfactory Letter of Credit providing for an annual drawdown by NIPSCO at the end of each year for three years. The annual drawdown shall be equal to one-third of the estimated costs, excluding overheads, after deducting estimated revenues.

4) Developer pays prime rate expense upfront on the total amount of estimated expenses, excluding overheads, with the interest rate applied to the remaining balance (estimated expenses minus estimated revenues) at the start of each year for a three year period. At the end of year three, the remaining balance will be paid to NIPSCO.

5) At the beginning of each year of a three-year period, developer will pay an annual amount equal to one-half of NIPSCO's discount rate multiplied by the remaining balance.

5. Midwest Independent System Operator (MISO)

The Midwest Independent System Operator will have primary responsibility for ensuring the reliable and economic operations of the electric transmission system in vast portions of the Midwest, once it becomes fully operational. The MISO consists of a diverse group of large and small utilities that include investor-owned, rural electric cooperative and municipally owned systems.

The MISO currently encompasses portions of eleven states (Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Ohio, Pennsylvania, Virginia, West Virginia and Wisconsin. In addition to utilities that serve Indiana (i.e., Cinergy, Hoosier Energy Rural Electric Cooperative, SIGECO and Wabash Valley Power Association), the MISO includes the following utilities: Allegheny Power, Ameren (formerly Union Electric of St. Louis and Central Illinois Public Service), Central Illinois Lighting Company, Commonwealth Edison (Illinois), Illinois Power, Kentucky Utilities, Louisville Gas & Electric and Wisconsin Electric.

The FERC gave conditional approval to the MISO on September 16, 1998.[13] Among other comments, the order stated:

> There is widespread agreement on the record that a large ISO would have five principal benefits. It would encourage the development of more competitive and efficient bulk power markets; reduce pancaking of transmission rates; increase power system reliability due to improved information and control over transmission facilities; allow more accurate ATC [Available Transmission Capacity] calculations; and facilitate more efficient congestion management.

The FERC agreed with the MISO and other parties (including the IURC) that the MISO would be more capable of managing the region's reliability and fostering improved economics if there were no "holes" caused by a lack of participation by transmission owning utilities in a much larger region. In the order, the FERC said:

> We acknowledge the concerns raised by intervenors on the size issue, and recognize the numerous and persuasive comments and testimony of those who assert that a Midwest ISO that would be larger than the one proposed and with fewer gaps than the one proposed would have significant additional reliability and competitive benefits over what has been proposed. We agree.

While American Electric Power (AEP), Indianapolis Power and Light (IPL) and Northern Indiana Public Service Company (NIPSCO) were initially involved in the formation of the MISO, all have thus far declined to become members. In an effort to increase its membership and geographic scope, the MISO has been in discussions with individual utilities, the members of the

[13] ER98-1438-000 Order Conditionally Authorizing Establishment of Midwest Independent Transmission System Operator and Establishing Hearing Procedures.

Alliance RTO, members of the Mid-continent Area Power Pool, and members of the Southwest Power Pool.

At its June 1999 meeting, the Midwest Independent System Operators Board of Directors, selected Indiana for their headquarters. The MISO anticipates employing about 150-175 persons with a large percentage of the work force being in highly technical fields. The MISO is in the process of recruiting key executives and expects to be operational in the last half of 2000.

6. The Alliance RTO Proposal

On June 3, 1999, American Electric Power, Consumers Energy, Detroit Edison, FirstEnergy and Virginia Electric and Power filed a request with the FERC to approve the Alliance Regional Transmission Organization (ARTO). On July 7, 1999, the IURC filed a protest and a request to intervene at the FERC. The IURC specifically asked the FERC to employ Alternative Dispute Resolution (ADR) to resolve some issues between the ARTO and other RTOs such as the Midwest ISO. The IURC expressed concern that the Alliance proposal does not fully comply with the eleven independent system operator principles articulated in the FERC's Order 888 and the FERC's Notice of Proposed Rulemaking (RM99-03-000) issued May 13, 1999.

In a response to the FERC regarding the protest and intervention filings, the Alliance RTO stated:

> Many of the protests repeat arguments that the Commission [FERC] has heard and rejected before. It should do so here as well. The Commission has also heard pleas to require mediation, dispute resolution, or merger with the MISO. These pleas should be rejected too.

While there are some attractive features to the ARTO, the IURC has expressed several concerns about the ARTO proposal. For example, the IURC is concerned that the ARTO is not large enough, it introduces operational complexities, and there is a lack of independence from market participants.

With regard to the concern that the ARTO does not cover a large enough geographical area, the IURC believes that a single RTO serving the entire Midwest region is necessary to ensure the reliable and economic operation of the regional transmission system. There appears to be a consensus on this point by all parties including state commissions, transmission customers, advocates for the MISO and proponents of the ARTO. Believing that the ARTO and the MISO have more in common than the issues that divide them was the basis for the recommendation by the IURC, and others, that compromise was both desirable and possible.

There are a number of operational concerns that would arise from the formation of the ARTO. One operational concern is that transactions from members of the MISO (as well as those utilities that are not affiliated with either the MISO or Alliance) would, in many instances, have to pay two transmission charges to members of the ARTO for transmitting power through the ARTO. This "pancaking" of transmission rates will reduce the ability of most Indiana utilities to transact power sales and purchases with utilities in the eastern United States. The existence of the ARTO will necessitate the development of a number of operational "protocols" between the MISO and the ARTO (and others) to ensure procedures for relieving transmission constraints.

C. Mergers and Acquisitions

Mergers are viewed with caution by federal and state regulatory commissions because the merged entity might exercise increased market power by setting price levels, limiting innovation, and restricting the range and quality of services to consumers' detriment. Mergers can also threaten state commerce by reducing job levels or draining employees from one state to another. Some mergers, however, result in substantial benefits to the merged companies, customers and employees of the merged companies. Evaluation of any merger or acquisition should objectively analyze both positive and negative potential outcomes. Since traditional merger evaluation criteria are premised on industries that are presently competitive, it is difficult to analyze mergers in the energy utility industry, which is still quite monopolistic.

In the last three years, electric utility mergers have proliferated. Of the thirty-nine mergers approved by the FERC since 1988, thirty-one have been filed with the FERC just since January 1996. Since 1996, twenty-five have been approved. So far in 1999, the FERC has received thirteen merger applications and approved six. This does not include two recently proposed mergers of Carolina Power & Light and Florida Progress or the proposed merger of SCANA (a holding company headquartered in South Carolina) and Public Service Company of North Carolina. Table 4 lists mergers that have been filed at the FERC since 1996.

Table 4: Mergers filed at the FERC Since January 1, 1996

Lead Docket No.	Principal Merging Entities	Status	Order Issued
EC95-16	Wisconsin Electric Power Company Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin)	Opinion issued, merger later withdrawn	5/14/97
EC96-2	Public Service Company of Colorado, Southwestern Public Service Company	Approved	3/12/97
EC96-7	Union Electric Company, Central Illinois Public Service Company	Approved	10/15/97
EC96-10	Baltimore Gas and Electric Company, Potomac Electric Power Company	Approved	4/16/97
EC96-13	IES Utilities, Inc., Interstate Power , Wisconsin Power & Light Company	Approved	11/12/97
EC96-30	Western Resources, Inc.	Withdrawn	N/A
EC96-36	Enron Corporation, Portland General Corporation	Approved	2/26/97
EC97-5	Ohio Edison Company, Centerior	Approved	10/29/97
EC97-7	Atlantic City Electric Company, Delmarva Power & Light Company	Approved	7/30/97
EC97-12	San Diego Gas & Electric Company, Enova Energy, Inc.	Approved	6/25/97
EC97-13	Duke Power Company, PanEnergy Corporation	Approved	5/28/97
EC97-19	Long Island Lighting Company, Brooklyn Union Gas Company	Approved	7/16/97
EC97-20	Destec Energy, Inc., NGC Corporation	Approved	6/25/97
EC97-22	PG&E Corporation, Valero Energy Corporation	Approved	7/16/97
EC97-23	Morgan Stanley Capital Group Inc. Dean Witter, Discover & Co.	Approved	4/30/97
EC97-24	NorAm Energy Services, Inc., Houston Industries, Inc.	Approved	7/30/97
EC97-46	Allegheny Energy, Inc., DQE, Inc.	Hearing	9/16/98
EC97-56	Western Resources Inc,. Kansas City Power & Light Company	Hearing	3/31/99
EC98-2	Louisville Gas and Electric Company, Kentucky Utilities Company	Approved	3/27/98
EC98-7	Salomon Inc. (Phibro), Travelers Group, Inc.	Approved	11/26/97
EC98-8	Wisconsin Energy Corporation, Inc., Edison Sault Electric Company	Approved	4/22/98
EC98-23	Duke Energy Corporation, Nantahala Power and Light Company	Approved	6/1/98
EC98-27	WPS Resources Corporation, Upper Peninsula Energy Corporation	Approved	5/27/98
EC98-40	American Electric Power Company, Central and Southwest	Hearing	11/10/98
EC98-62	Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc.	Approved	1/27/99
EC98-63	MidAmerican Energy Holdings Company, CalEnergy Company, Inc.	Approved	12/16/98
EC99-1	Sierra Pacific Power Company, Nevada Power Company	Approved	4/15/99
EC99-33	BEC Energy, Commonwealth Energy System	Approved	7/1/99
EC99-40	CILCORP Inc., The AES Corporation	Approved	6/16/99
EC99-48	Sempra Energy, KN Energy, Inc.	Withdrawn	N/A
EC99-49	New England Electric System, National Grid Group plc	Approved	6/16/99
EC99-50	PacifiCorp, ScottishPower plc	Approved	6/16/99
EC99-70	New England Electric System, Eastern Utilities Associates	Pending	N/A
EC99-73	El Paso Energy Corporation, Sonat Inc.	Pending	N/A
EC99-81	Dominion Resources, Inc., Consolidated Natural Gas Company	Pending	N/A
EC99-92	Texas-New Mexico Power Co., SW Acquisition, LP	Pending	N/A
EC99-99	Illinova Corp, Dynegy Inc.	Pending	N/A
EC99-101	Nothern States Power Co. (Minnesota), New Century Energies, Inc.	Pending	N/A
EC99-106	Southern Indiana Gas and Electric Co., Indiana Gas Co.	Pending	N/A

Prior to 1996, electric utility merger applicants typically argued that customers would realize substantial savings due to the coordination of generating unit dispatch and other operations. In April 1996, the FERC issued Order 888, which requires transmission-owning utilities to allow other power suppliers to have equal access to their transmission systems on non-discriminatory terms. As a result, many of the previously touted coordination benefits can now be achieved without a merger.

Today, mergers of both electric and gas utilities frequently produce comparatively small savings from reduced administrative costs and other economies of size (scale). Generally, merging companies in all industries tend to overestimate potential savings. Empirical results for electric and gas utilities support this conclusion. While mergers can produce some economies of size, there are also inefficiencies associated with the operations of a much larger organization. As a result, the actual savings for customers may be small and outweighed by other factors such as increased market power, decreased customer choice and increased control by the merged entity of distribution facilities.

1. Electric and Gas Mergers in Indiana

- **AEP – CSW Merger**

On December 22, 1997, American Electric Power (AEP) and Central and South West Corporation (CSW) announced a stock-for-stock merger transaction creating a company with a total market capitalization of approximately $28.1 billion ($16.5 billion in equity; $11.6 billion in debt and preferred stock). A merger between AEP and CSW will create the largest electric utility holding company in North America in terms of generating capacity.

On June 29, 1998, the IURC announced an investigation into the merger between AEP and CSW.[14] During the course of the Commission's investigation of the AEP/CSW merger, a settlement was reached between AEP and the Commission's negotiating team (In the Matter of the Investigation of the Commission's Own Motion Into Any and All Matters Relating to the Merger of American Electric Power, Inc., and Central and South West Corporation). The settlement agreement approved by the IURC requires the companies to share $66.2 million of merger benefits (in the form of rate reductions) with customers during the first eight years of the merger.[15] In addition to sharing some of the direct financial benefits, the following is a partial list and summary of other elements of the settlement agreement:

[14] Cause No. 41210.
[15] Order in Cause 41210.

- AEP's Indiana operating company (I&M) agreed to maintain its reliability and quality of service levels and provide annual reports on reliability and quality of service. The reports will include both the average duration of interruptions as well as the frequency of interruptions.

- All savings from fuel and purchased power costs shall be flowed through to customers.

- AEP agreed not to seek recovery of any stranded costs associated with the operating companies of one AEP zone from the retail customers of the other AEP zone.

- Any proceeds from the sale of AEP's facilities will go to the AEP operating company (e.g., I&M) in whose ratebase the facilities are included for further disposition by the state regulatory commission.

- In an effort to mitigate both the perception and incidence of exercising market power, AEP will file with the FERC an unconditional application, consistent with the RTO agreement and tariff, to transfer control of its bulk transmission facilities in Indiana or other states to the Midwest Independent Transmission System Operator or another FERC-approved RTO.

- AEP will abide by affiliate standards that govern transactions among affiliated utilities and other affiliated businesses in order to prevent subsidization of any affiliate. Rates to customers will only reflect the costs actually incurred by AEP in providing service; separate books and records will be maintained for each of its affiliates.

- If the PUHCA is repealed, AEP will work with the state commissions to ensure that AEP continues to furnish necessary information.

The IURC intervened in the three FERC dockets initiated in connection with the proposed merger.[16] As part of the settlement agreement approved by the IURC, the IURC agreed not to oppose the merger at the FERC. In the order the Commission said that it would actively participate in any proceedings at the FERC arising from any RTO filings made by AEP that did not at least meet the minimum standards espoused by the IURC. The minimum standards contained in the FERC's Notice of Proposed Rulemaking in the Regional Transmission Organizations (Docket No. RM99-2-000) satisfies many of the fundamental concerns that have been raised by the IURC. The order specifically states:

[16] Docket Nos. ER98-2786-000, EC98-40-000, and ER98-2770-000.

> The IURC will be assertive before the FERC to ensure that AEP joins an RTO and, to the maximum extent possible, that the RTO satisfies the conditions espoused by the IURC. The IURC is satisfied that nothing in this agreement prevents the IURC from advocating these concerns to the FERC . . . or assisting the parties in bridging the remaining differences.

The proposed merger of AEP and CSW is still pending at the FERC with the FERC expected to issue an order before the end of 1999. The Citizens Action Coalition appealed the IURC's decision approving the settlement of the merger investigation to the Indiana Court of Appeals.

- **Indiana Gas - SIGECO Merger**

The proposed merger of Indiana Energy with SIGCORP to form a new holding company named Vectren will be considered by the IURC in the context of the Indiana Supreme Court's ruling that the IURC does not have authority over mergers (discussed later). If consummated, the tax-free stock-for-stock transaction will create a combined company with a total enterprise value of approximately $1.9 billion. Indiana Energy's and SIGCORP's utility companies will remain separate subsidiaries of Vectren and will continue to operate under their current corporate names. Vectren will be based in Evansville, which will also remain home to SIGECO; Indiana Gas will continue to be headquartered in Indianapolis.

The companies assert that the merger would save $200 million over ten years by eliminating duplicate corporate and administrative functions and through greater efficiencies in operations. According to the companies, position reductions are expected to be 120 of the combined total of 1,850 jobs.

In contrast to the willingness of AEP and CSW to share over $66 million in merger benefits over eight years, Indiana Gas and SIGECO have stated that they do not intend to share any of their estimated $200 million in merger savings with their customers.[17] Indiana Gas and SIGECO's decision to not allocate direct savings to customers is troubling. The IURC is concerned that its lack of authority to approve mergers will adversely affect the Commission's authority to assure that the customers of merging companies are receiving some of the measurable benefits of any proposed merger.

2. Convergence Mergers and Acquisitions

Convergence mergers and acquisitions involve companies in previously unrelated markets that combine in order to achieve "economies of scope" so that services in both markets can be

[17] Petition of Indiana Gas and Southern Indiana Gas Company in Cause No. 41465.

provided more economically than either firm could provide on a stand-alone basis. In recent years, electric and gas utilities have undertaken a wide range of mergers and acquisitions involving entities other than electric and gas companies. For example, NiSource owns Indianapolis Water. Southern Indiana Gas & Electric Company, Cinergy and American Electric Power all own telecommunications companies. Indiana utilities, like utilities throughout the United States, are involved in varied enterprises such as home security, real estate and appliance repair.

While convergence mergers and acquisitions may provide better service to customers of the regulated utility, there is a concern that customers in the regulated business could subsidize the operations of the unregulated firms in competitive markets. There is also a concern that the regulated firm could improperly share information with an affiliate to the detriment of competitors and, ultimately, to the detriment of consumers. Regulated utilities can also use financial resources to acquire other businesses rather than using financial resources to reduce stranded costs.

3. The Indiana Utility Regulatory Commission's Authority over Mergers and Acquisitions

The IURC's statutory authority over mergers and acquisitions evolved from a 1913 statute that has been amended over the years in response to changes in the regulated markets such as the abuses of holding companies during the depression.[18] Federal statutory authority evolved, in part, from the depression era abuses involving a handful of multi-state utility holding companies that controlled most of the nation's utilities. In response to these abuses, Congress enacted the Public Utility Holding Company Act (PUHCA) of 1935 to limit the power of holding companies. Since the depression, the energy industry has dramatically transformed from localized markets to regional (and to some extent, national) markets.

The IURC's authority over mergers was recently tested in the July 30, 1999, case involving the Ameritech – SBC Merger. In this case, the Indiana Supreme Court held: "[S]ection 83(a) does not confer Commission jurisdiction over transactions in the outstanding securities of a public utility or its parent." In response to the Supreme Court's decision, Ameritech withdrew its commitments to the consumers and to the State of Indiana, which included six specific initiatives intended to foster local competition. Unless 8-1-2-83 is amended by the legislature, the IURC is clearly precluded from reviewing most, if not all, mergers and acquisitions. The Court specifically noted that if the

[18] I.C. 8-1-2-83. *(Formerly Acts: 1913, c.76, s95; Acts 1925, c.54, s.1.) As amended by P.L. 59-1984, SEC.37; P.L.23-1988, SEC. 24: P.L.8-1993, SEC.111. and* I.C. 8-1-2-84: *(Formerly Acts: 1913, c.76, s95.5; Acts 1925, c.54, s.2., Acts 1939, c.19, s.3,; Acts 1973, P.L.61, SEC.1,) As amended by P.L. 23-1988, SEC.25; P.L-1-1989, SEC. 15: P.L.12-1992, SEC.57.*

Commission is to acquire jurisdictions over mergers, the jurisdiction must be specifically conferred by the legislature.[19] In writing for the Majority, Justice Boehm stated:

> The Commission and others make several compelling arguments, all of which boil down to the need for pre-merger investigation and approval by the Commission to protect the consumers of Indiana . . . It may well be that it is more efficient or effective in protecting the interests of the citizens of our state for the Commission to have power to disapprove a shift in control of a utility, rather than simply power to regulate the utility after its ownership is transferred.

In his Minority Opinion Chief Justice Shepherd observed that, as a state we have missed opportunities in banking, and possibly with our policies toward the insurance industry. The Chief Justice wrote:

> I find some modest solace in the acknowledgement of my colleagues that the policy arguments favoring supervision of business combinations . . . are compelling . . . [W]e cannot hope to thrive in the modern global economy unless our state acts with force and foresight at every opportunity.

The IURC's current authority is likely to be limited to trying to protect Indiana consumers from adverse effects from a merger rather than having any direct authority over the merger. Merger review and approval authority, including the ability to condition merger approval on requiring the merging companies to take specific steps to mitigate market power, is essential for the protection of customers from potential abuses of market power. It is also necessary for the Commission to have the requisite authorities and staff to ensure compliance.

4. Federal Jurisdiction over Mergers and Acquisitions

While it is true that some mergers are reviewed at the federal level, no federal agency is charged with specifically protecting the interests of consumers in Indiana. The FERC's merger review, for example, has a national focus and does not generally concern itself with the potential ramifications on any particular state.[20] Consequently, the FERC is not likely to be overly concerned by the acquisition of an Indiana utility by an out-of-state entity or by an Indiana utility's acquisition of an out-of-state energy company. In some circumstances, the FERC's authority to review some types of mergers may also be at issue. In one recent case, for instance, the FERC Commissioners

[19] Indiana Bell Telephone Co. d/b/a Ameritech and SBC Communications, Inc. v. Indiana Utility Regulatory Comm'n, et al., 1999 Ind. LEXIS 548 (July 30, 1999).

[20] The FERC's authority to approve mergers, or to condition its approval of a merger, is based on Sections 201 and 203 of the Federal Power Act.

were divided on the FERC's jurisdiction to approve acquisitions of United States utilities by foreign entities.[21]

The Securities & Exchange Commission (SEC), Department of Justice (DOJ) and the Federal Trade Commission (FTC) also have limited merger approval authority. The SEC's review seems to be shadowed by an expectation that the Public Utility Holding Companies Act (PUHCA) will be repealed and the SEC's authority will soon be ceded to the FERC and/or to the states. The DOJ and FTC have thus far been much more involved in the review of telecommunications mergers than in the review of electric or gas utility mergers. The DOJ and the FTC, of course, also have to spread their limited resources to address all other types of industries in the United States economy and should not be counted on to devote resources to specifically safeguard the interests of Indiana.

5. Merger Authority Available to Selected State Commissions

The following are brief excerpts directly from state statutes of merger authorities that are vested in a few selected state commissions:

<u>California</u>

(b) "Before authorizing the merger, acquisition, or control of any electric, gas, or telephone utility organized and doing business in this state, where any of the utilities that are parties to the proposed transaction has gross annual California revenues exceeding five hundred million dollars ($500,000,000), the commission shall find that the proposal does all of the following:

(1) Provides short-term and long-term economic benefits to ratepayers.

(2) Equitably allocates, where the commission has ratemaking authority, the total short-term and long-term forecasted economic benefits, as determined by the commission, of the proposed merger, acquisition or control between shareholders and ratepayers. Ratepayers shall receive not less than 50% of those benefits.

(3) Not adversely affect competition. In making this finding, the commission shall request an advisory opinion from the Attorney General regarding whether competition will be adversely affected and what mitigation measures could be adopted to avoid this result.

(c) Before authorizing the merger, acquisition, or control of any electric, gas, or telephone utility organized and doing business in the state...the commission shall consider each of the criteria listed in paragraphs (1) to (8) inclusive, and find, on balance, that the merger, acquisition or control proposal is in the public interest.

[21] EC99-49-000, New England Electric System and National Grid Group (United Kingdom) plc.

(1) Maintain or improve the financial condition of the resulting public utility doing business in the state.

(2) Maintain or improve the quality of service to public utility ratepayers in the state.

(3) Maintain or improve the quality of management of the resulting public utility doing business in the state.

(4) Be fair and reasonable to affected public utility employees, including both union and non-union employees.

(5) Be fair and reasonable to the majority of all affected public utility shareholders.

(6) Be beneficial on an overall basis to state and local economies, and to the communities in the area served by the resulting public utility.

(7) Preserve the jurisdiction of the commission and the capacity of the commission to effectively regulate and audit public utility corporations in the state.

(8) Provide mitigation measures to prevent significant adverse consequences which might result.

(d) When reviewing a merger, acquisition or control proposal, the commission shall consider reasonable options to the proposal recommended by other parties, including no new merger, acquisition, or control, to determine whether comparable short-term and long-term economic savings can be achieved through other means while avoiding possible adverse consequences of the proposal.

Illinois

(b) No reorganization shall take place without prior Commission approval. The Commission shall not approve any proposed reorganization if the Commission finds, after notice and hearing, that the reorganization will adversely affect the utility's ability to perform its duties under this Act. In reviewing any proposed reorganization, the Commission shall find that:

(1) the proposed reorganization will not diminish the utility's ability to provide adequate, reliable, efficient, safe, and least-cost public utility service;

(2) the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers;

(3) costs and facilities are fairly and reasonably allocated between utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility for ratemaking purposes;

(4) the proposed reorganization will not significantly impair the utility's ability to raise necessary capital on reasonable terms or to maintain a reasonable capital structure;

(5) the utility will remain subject to all applicable laws, regulations, rules, decisions, and policies governing the regulation of Illinois public utilities;

(6) the proposed reorganization is not likely to have a significant adverse effect on competition in those markets over which the Commission has jurisdiction;

(7) the proposed reorganization is not likely to result in any adverse rate impacts on retail customers.

(c) The Commission shall not approve a reorganization without ruling on: (i) the allocation of any savings resulting from the proposed reorganization; (ii) whether the companies should be allowed to recover any costs incurred in accomplishing the proposed reorganization and, if so, the amount of costs eligible for recovery and how the costs will be allocated.

Oklahoma

A. The Corporation Commission shall approve any merger or other acquisition of control referred to in Section 2 of this act unless, after a public hearing thereon, it finds that one or more of the following conditions will exist if such merger or other acquisition of control is consummated, in which event it shall disapprove such merger or acquisition of control and the same shall not be consummated.

(1) The acquisition of control would adversely affect the contractual obligations of the domestic public utility, or its ability or commitment to continue to render the same level of service to its customers that the domestic public utility is currently rendering;

(2) The effect of the merger or other acquisition or control would be substantially to lessen competition in the furnishing of public utility service in the state;

(3) The financial condition of any acquiring party is such as might jeopardize the financial stability of the domestic public utility or any person controlling such domestic public utility or otherwise prejudice the interest of the domestic public utility's customers;

(4) The plans or proposals which an acquiring party has to liquidate the public utility or any such controlling person, sell its assets, or a substantial part thereof, or consolidate or merge it with any person, or to make any other material change in its investment policy, business or corporate structure or management, would be detrimental to the customers of the domestic public utility and not in the public interest.

(5) The competence, experience and integrity of those persons who would control the operation of the domestic public utility are such that it would not be in the interest of its customers and the public to permit the merger or other acquisition of control.

Texas

(a) Unless a public utility reports the transaction to the Commission within a reasonable time, the public utility may not:

(1) sell, acquire, or lease a plant as an operating unit or system in this state for a total consideration of more than $100,000; or

(2) merge or consolidate with another public utility operating in this state.

(b) A public utility shall report to the commission within a reasonable time each transaction that involves the sale of at least 50% of the stock of the utility. On the filing of a report with the commission, the commission shall investigate the transaction, with or without a public hearing, to determine whether the action is consistent with the public interest. In reaching this determination, the commission shall consider:

(1) the reasonable value of property, facilities, or securities to be acquired, disposed of, merged, transferred, or consolidated;

(2) whether the transfer will

(A) adversely affect the health or safety of customers or employees;

(B) result in the transfer of jobs of citizens of this state to workers domiciled outside the state; or

(C) result in a decline of service;

(3) whether the public utility will receive consideration equal to the reasonable value of the assets when it sells, leases or transfers assets; and

(4) whether the transaction is consistent with the public interest.

Minnesota

Subdivision 1. Commission approval required. No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for total consideration in excess of 100,000, or merge or consolidate with another public utility operating in this state, without first being authorized so to do by the commission. Upon the filing of an application for the approval and consent of the commission thereto the commission shall investigate, with or without public hearing, and in case of a public hearing, upon such notice as the commission may require, and if it shall find that the proposed action is consistent with the public interest it shall give its consent and approval by order in writing. In reaching its determination the commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of, or merged and consolidated...

6. Enforcement Authorities Required by the IURC

Based on the IURC's experience in the telecommunications industry, it seems certain that our inability to enforce our orders and rules will pose similar problems in the natural gas and electricity markets as those markets become increasingly competitive. These concerns are not unique to Indiana. Other states, particularly those that have adopted retail competition legislation, have felt compelled to vest their state commissions with substantial enforcement authorities. The telecommunications industry has demonstrated that effective competition depends on state commissions establishing "rules of the road" that include meaningful deterrents that can be imposed upon those who block or delay competition.

As some markets for electricity and gas become increasingly competitive while others remain regulated, there will be increasing tension for incumbent energy suppliers to gain competitive advantages by having captive customers in regulated markets subsidize operations in competitive markets. The FERC, for instance, adopted "Codes of Conduct" in an attempt to prevent some practices that would impede the development of a competitive wholesale market. In retail markets, some states have also adopted "Codes of Conduct" and "Affiliate Rules." The adoption of these rules is intended to prevent certain anticompetitive actions by regulated utilities vis a vis other market participants and with regard to their affiliates. Certainly, if the experience in telecommunications holds true for energy markets, we can expect the incumbent energy suppliers to erect barriers to keep out competition.

The Commission must have the tools to ensure that utilities provide adequate service for captive customers as the market transitions to greater competition. Preventing direct cross-subsidization of competitive markets by captive customers in regulated markets is just one example of the concerns that will have to be addressed by policymakers. Our experience in telecommunications (which, unfortunately, is commonplace in other states as well) demonstrates that firms minimize expenditures for captive customers and infrastructure. In some instances, reduced expenditures can be manifested in a deterioration of services such as connecting new customers or making repairs in a timely manner. In other instances, reduced expenditures can impede the introduction of new technologies or the modernization of facilities. The decision to cut expenditures in the provision of reliable and high quality service might be done in order to improve the utility's financial position in other more competitive markets. As a consequence, there is a real concern that captive customers pay more for a lower quality of service.

In addition to a grant of legislative authority to establish a framework for effective competition, there will be a need for additional resources to monitor the markets, enforce Commission rules and regulations and remedy abusive behavior. Enforcement authority, without the requisite tools to adequately implement the public policy wishes of the State of Indiana, is tantamount to having no authority.

D. State Competition Initiatives in Electricity

Electric utility restructuring continues to be an active issue in many states. New restructuring legislation has recently passed in Ohio, Arkansas, New Jersey and Texas. Consumers in Illinois will begin receiving electricity from alternative suppliers in October 1999. Electric industry restructuring in California has received mixed reviews after more than a year of retail competition. The following discussion highlights the states mentioned above along with Kentucky and Michigan. Appendix 3 presents a summary of restructuring activities by state.

California

After a year of operation California's retail electric market has received mixed reviews. Consumer groups maintain that residential and small business customers have failed to benefit during the first year as utilities have retained their monopoly advantages and prevented competitors from offering lower electricity prices.

A utility industry group argues that restructuring has given all electricity customers a choice of power suppliers and lower electric rates have attracted new business and economic growth to the state without sacrificing system reliability.

The Utility Reform Network (TURN) is not convinced that residential consumers have benefits, and states that because of utilities' monopoly stranglehold, fewer than one percent of the state's residential customers have switched electricity providers, while aggregation has failed to provide a means for small customers to secure lower prices. Moreover, a legislated ten percent rate cut for small customers has been eroded to just two percent by mandatory financing charges on rate reduction bonds by the state's three investor-owned utilities.

Californians for Affordable & Reliable Electric Service (CARES), on the other hand, argues that the California Power Exchange has enabled large and small retail customers alike to monitor the price of power and adjust their energy usage to lower their costs and increase efficiency. While acknowledging that residential and small business customers have been slow to switch to new energy service providers, CARES disputes that it indicates flaws in the design or operation of the state's competitive electric market. Rather, deregulation has created a more efficient market with competitive opportunities that will result in greater price savings when the transition period ends in 2002.

The California Independent System Operator (ISO) issued a report March 31, 1999, describing the first year of operation as "trial by fire." Despite weathering volatility and seasonal price spikes in its ancillary services market, the ISO exceeded its projections, processing nearly 700 energy schedules per hour from 27 active scheduling coordinators while delivering electricity without any major power disturbances.

The ISO's computerized control center routed 167 billion kWh of electricity in its first nine months of operation, 3 billion kWh more than its annual projections. As a result the Cal ISO was able to lower its grid management charges in 1999 by half a cent to .77 cents per MWh. Cal ISO transmission charges amounted to about 47 cents for the average customer of an investor-owned utility with a typical monthly household bill of $76.31.

Illinois

There has been significant restructuring activity in Illinois over the past 12 months as the implementation of customer choice commences.

The Illinois Commerce Commission (ICC) ruled that a lottery to determine which commercial customers will be eligible to participate in customer choice beginning October 1, 1999, must select candidates from among customers who have previously registered with the local utility rather than from the at-large pool of commercial users.

Electric utilities were joined by the ICC staff in recommending to the commission that lottery candidates be drawn from the entire pool of commercial customers not otherwise qualified under the 4 MW and 95 MW categories. Utilities characterize a pre-lottery registration as a "first-come, first-served" approach that violates the Illinois restructuring law because it is discriminatory, allowing the same interested, well-informed customers to sign up each time.

Arguing on behalf of the registration process were Black-Hawk Energy Services, Enron and NEV Midwest, New Energy Ventures' operational subsidiary serving Illinois. They asked the ICC to adopt a selection process similar to other lotteries where there is an enrollment process, such as the Illinois State Lottery. The three companies objected to the utilities' proposal on the basis that it would result in the selection of eligible customers who are uninterested in or unsuited for delivery services.

In addition, power marketers saw the utilities' proposal as anti-competitive. If adopted, it would result in direct access participation far short of the one-third of utilities' non-residential load envisioned by the legislation.

In its February 26, 1999, order, the ICC stated that it was "reasonable to conclude that initiating the selection process with a registration requirement is likely to lead to greater competition than if no action were required on the part of the customer."

The ICC also ruled in favor of the power marketers on the disclosure of utility rate classification data. All parties agreed that utilities would release customer names and addresses unless the customer specifically forbade the utility from releasing the information.

Michigan

Although the Michigan Public Service Commission (PSC) has set September 20, 1999, as the date final bids are due on the first block of capacity for open access, customers contemplating choice are facing two looming developments before moving forward: the pending Michigan Supreme Court decision on whether the PSC has statutory authority to order retail wheeling in Michigan, and new electric industry restructuring legislation introduced in June 1999.

The new legislation, spearheaded by the Michigan Chamber of Commerce, contains provisions not included in the PSC's regulation-based direct-access rules.

Senate Bills 642, 643 and 644 and House Bills 4789, 4790 and 4791 have been introduced to provide a focal point for negotiations over the summer in an effort to build consensus by September 1999.

Among the key provisions of the proposed legislation is one that prohibits generation rate deregulation until Michigan lawmakers decide that competition exists. Under this provision, the PSC beginning in late 2002, is directed to compile annual reports on the state of competition in Michigan.

The bills call for a series of market power mitigation efforts to encourage competition. A legislative finding that competition exists allows the PSC to deregulate generation rates on a customer class basis, although rates cannot exceed utility tariffs in place as of December 31, 1998.

A legislative finding that competition does not exist in a given customer class allows the commission to regulate the generation rates of large utilities, subject to the rate cap. The PSC can reduce rates, however.

Further, Consumers Energy and Detroit Edison are required to upgrade their transmission import capacity or suffer penalties, and they are directed to join a FERC approved regional transmission operator (RTO) that will assure non-discriminatory access to the transmission systems and encourage system upgrades on a regional basis. The proposal provides penalties for failure to join such a RTO or similar organization within a specified period. Consumers Energy and Detroit Edison are members of the ARTO which currently has an application pending at the FERC.

In addition, utilities are required to functionally, and in some cases structurally, separate their business units in order to assure that their regulated rates do not subsidize their competitive businesses.

Assuming ratification by the Michigan Supreme Court of the Michigan Public Service Commission's authority to order electric industry restructuring, direct access is set to commence early in the fourth quarter 1999. Final bids are due on the first block of capacity for open access by September 20, 1999. Bids for the next three blocks are due November 19, 1999, January 20, 2000, and March 20, 2000.

Consumers Energy and Detroit Edison will be required to offer standby service on a "best-efforts" basis. According to the PSC, standby service must be available to open access customers who request it, but the two utilities are not required to build or purchase new capacity, nor must they interrupt firm customers to offer it. Standby service is to be available as long as the utilities are unable to make firm transmission service available to the open access customer and his supplier. The PSC ordered the utilities to charge their top incremental cost plus one-cent/kWh for standby service.

Ohio

Senate Bill 3 was passed by the Ohio House of Representative on June 17, 1999, and was approved by the Senate in a concurrence vote on June 22, 1999. Governor Robert Taft has signed the measure that becomes effective October 6, 1999. The transition to a restructured electric industry will begin on January 1, 2001.

Prior to the final vote, the Senate approved an amendment that deleted a controversial provision to "auction" customers who did not switch electric suppliers by the end of the transition period. Consumer groups generally favored the auction while the state's investor-owned utilities strongly opposed it.

Senate Bill 3 guarantees a five percent rate cut for residential customers for 2.5 years, or halfway through a transition period ending December 31, 2006. For many ratepayers, the savings will amount to between $2 and $3 a month. The law also makes provision for a customer education program. The Public Utility Commission of Ohio (PUCO) will require electric companies to spend more than $30-million over the next six years informing the public on how to shop for alternative energy suppliers.

The critical issue of determining stranded costs for utilities will be left to the Ohio Public Utilities Commission, a provision disliked by both utilities and consumer advocates. Utilities want the right to recover as much as $13 billion to $14 billion in stranded costs, mostly for nuclear investments. Consumer groups contend any stranded cost recovery is unjustified.

Other provisions in the legislation include:

- a requirement that electric generators purchase excess electricity from small businesses and residents who have renewable energy sources, such as solar and wind
- the establishment of a $100-million low-interest loan fund that will provide below-market interest rates for homeowners and small businesses who want to invest in energy efficiency.

The utilities are required to file transition plans during the fall of 1999. The PUCO will hold public hearings on the plans during the spring of 2000. The PUCO will issue orders on the utilities' plans by October 2000.

E. Review of the Natural Gas Industry

1. Industry Structure

Gas utilities in the United States are categorized into municipally owned and investor-owned. Despite their different forms of ownership and corporate structures, municipal and investor-owned utilities share the goal of providing reliable gas service at reasonable cost. Because of the differences in governance and corporate structure, government policy does not affect each type of utility in the same manner.

- **Investor-Owned Utilities (IOU)**

Investor-owned utilities are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, and two of them, NIPSCO and SIGECO, also operate major electric utilities. Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

- **Municipally Owned Utilities**

There are 19 municipally owned gas utilities in Indiana. The largest municipal gas utility is Indianapolis-based Citizens Gas and Coke. Of the 19 municipal gas utilities in Indiana, three are regulated by the IURC. Municipals are organized as not-for-profit local government agencies and pay no taxes or dividends, although net revenue can be turned over to the general city fund (in lieu of taxes) if the city elects to do so. Municipal utilities raise capital through the issuance of tax-free bonds.

Like their IOU counterparts, municipal gas utilities serve as a "reseller" and transporter to their retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities.

- **Indiana Sales and Transportation of Gas**

Local distribution companies (LDCs) serve as both merchants, providing bundled sales and transportation service to many of their customers, and transporters, moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers.

The following tables show the sales, transportation and throughput percentage for Indiana's four largest LDCs. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the gas and transportation service. Transportation figures include only volumes of gas owned by end users that move through an LDC's system. Throughput figures include all volumes of gas moving through the LDC's system regardless of ownership.

Table 5 presents sales information for Citizens Gas, Indiana Gas Company, NIPSCO and SIGECO. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix 2.

Table 5: Sales (Dth) for the Four Largest Gas Utilities in Indiana -- 1998

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	21,152,055	10,869,253	2,461,149	15,000	34,497,457
Indiana Gas	38,806,564	15,487,999	8,510,580	-	62,805,143
NIPSCO	58,346,000	22,303,000	11,897,000	22,795,000	115,341,000
SIGECO	7,924,707	3,401,010	513,612	(223,594)	11,615,735

Source: IURC data requests

2. U.S. Average Natural Gas Prices

Table 6 provides a comparison of average natural gas price by sector and state for 1997 and 1998. The price to Indiana residential and commercial customers is below the national average for both years.

Table 6: Average Price* of Natural Gas by Sector and State -- 1998 and 1997

	Citygate Price		Residential		Commercial		Industrial		Electric Utilities	
State	1998	1997	1998	1997	1998	1997	1998	1997	1998	1997
Alabama	3.05	3.98	7.19	7.81	6.48	6.96	3.13	4.10	2.73	3.08
Alaska	1.74	1.85	3.63	3.67	2.45	2.56	1.51	1.56	1.86	1.68
Arizona	2.42	3.26	7.33	6.82	5.58	5.11	3.52	4.06	2.71	4.81
Arkansas	3.03	3.50	6.46	6.28	5.13	5.17	3.72	3.91	2.21	3.60
California	2.29	3.28	6.87	6.30	6.81	6.92	4.31	5.05	2.88	4.50
Colorado	n/a	3.30	4.52	4.23	4.10	3.76	2.64	4.25	2.81	3.59
Connecticut	5.12	5.58	10.30	10.28	7.48	7.96	5.00	5.57	2.73	3.20
Delaware	2.81	4.54	8.10	7.68	6.72	6.37	4.03	4.95	4.86	3.80
Florida	3.43	4.44	10.43	10.28	6.75	6.69	4.44	4.38	2.36	3.07
Georgia	3.46	4.28	6.13	7.24	5.86	6.79	5.39	4.95	2.54	3.89
Hawaii	6.13	6.79	20.11	23.02	14.15	15.00	0.00	0.00	0.00	0.00
Idaho	1.88	2.15	5.10	4.85	4.42	4.33	3.09	2.76	0.00	0.00
Illinois	2.81	3.34	4.89	6.03	4.60	5.58	4.14	4.93	2.26	3.15
Indiana	**2.42**	**3.35**	**6.15**	**6.04**	**5.63**	**5.34**	**4.52**	**4.48**	**3.21**	**4.41**
Iowa	3.56	3.63	5.12	5.62	4.21	4.99	1.48	4.19	3.20	4.47
Kansas	3.04	3.69	5.78	6.29	4.81	5.68	3.72	3.78	2.73	3.86
Kentucky	3.18	3.77	5.41	5.93	5.46	5.70	4.31	4.42	3.53	4.36
Louisiana	2.53	3.37	5.71	6.90	5.32	6.58	2.72	3.22	2.55	3.67
Maine	3.25	4.31	7.90	8.45	7.41	7.97	6.21	7.04	0.00	0.00
Maryland	3.33	3.88	7.42	7.98	6.23	6.69	6.00	2.79	3.52	5.18
Massachusetts	3.23	3.80	9.27	9.50	7.52	8.19	6.75	7.36	3.08	4.04
Michigan	2.93	3.37	4.82	4.99	4.71	4.92	3.88	3.94	0.65	0.58
Minnesota	3.07	3.66	5.11	5.71	4.45	5.09	3.11	3.66	2.63	2.43
Mississippi	n/a	3.68	n/a	5.87	4.71	5.36	n/a	3.83	2.47	3.44
Missouri	2.97	3.60	5.94	6.41	5.69	6.23	4.78	5.43	2.70	5.11
Montana	2.54	3.39	4.94	4.51	4.90	4.61	4.88	4.73	6.28	5.38
Nebraska	3.40	3.83	5.00	5.54	5.03	5.27	3.31	4.36	3.36	3.21
Nevada	3.08	3.62	6.69	5.66	5.69	4.89	5.98	7.40	2.39	2.23
New Hampshire	3.80	4.47	8.38	9.23	706.	8.61	6.14	7.09	0.00	0.00
New Jersey	3.74	4.33	7.34	7.69	4.27	6.99	3.46	4.96	2.91	4.04
New Mexico	2.16	2.76	4.34	5.36	3.93	4.12	3.41	2.86	2.37	3.47
New York	n/a	3.67	8.64	9.46	n/a	7.56	4.52	6.11	2.98	3.63
North Carolina	3.54	4.15	8.04	8.93	6.77	7.65	4.52	5.33	3.02	6.89
North Dakota	2.90	3.52	4.65	4.37	4.10	4.02	3.15	3.08	0.00	0.00
Ohio	4.66	5.23	6.00	6.70	5.68	6.35	5.43	5.15	3.25	4.30
Oklahoma	2.64	3.47	5.57	5.90	5.46	5.71	4.13	4.82	3.69	4.28
Oregon	n/a	2.46	n/a	5.93	n/a	4.55	n/a	3.17	1.09	1.96
Pennsylvania	4.16	3.98	8.54	7.91	7.27	7.31	4.65	5.01	2.71	3.73
Rhode Island	3.55	4.12	8.90	9.10	7.80	8.08	4.28	2.74	3.39	3.63
South Carolina	3.26	3.81	8.17	8.56	6.81	7.56	3.53	4.16	3.92	6.20
South Dakota	3.12	3.71	5.12	5.20	4.19	4.34	3.31	4.13	0.00	0.00
Tennessee	n/a	3.66	n/a	6.84	n/a	6.27	n/a	4.76	0.00	0.00
Texas	3.02	4.14	8.54	5.98	4.80	5.20	2.52	3.18	2.45	3.39
Utah	3.38	2.70	5.70	4.99	4.43	3.79	3.10	2.43	0.00	0.00
Vermont	2.70	1.96	6.24	6.05	5.18	5.20	3.01	3.18	2.92	4.19
Virginia	3.62	4.26	7.98	8.09	6.20	6.53	4.61	6.29	3.31	2.87
Washington	n/a	2.71	n/a	5.44	n/a	4.66	n/a	3.71	1.67	4.93
West Virginia	2.96	3.21	6.81	6.76	6.30	6.06	2.85	3.12	5.59	6.10
Wisconsin	3.18	3.60	6.07	6.52	5.11	5.60	4.11	4.36	2.90	3.94
Wyoming	n/a	3.69	n/a	3.83	n/a	3.46	n/a	3.51	8.60	8.78
Average	**3.20**	**3.78**	**6.38**	**6.70**	**5.52**	**6.04**	**3.53**	**4.10**	**2.58**	**3.51**

n/a = Not Available * (Dollars per Thousand Cubic Feet, the information is preliminary based on year-to-date information)

Source: US Department of Energy, Energy Information Administration, Natural Gas Monthly, June 1999, tables 20-24.

F. Recent Developments in Natural Gas

1. NIPSCO Alternative Regulatory Plan

To date, NIPSCO is the only natural gas utility in Indiana with a program to allow some of its residential and small commercial customers to purchase their gas from a supplier other than the incumbent local distribution company. The Commission approved NIPSCO's "Choice" program in Cause No. 40342 on October 8, 1997, based on Indiana Code 8-1-2.5.

The first phase of this program (December 1997 through July 1998) was opened to customers in parts of St. Joseph County and included South Bend, Mishawaka, Granger and surrounding areas. Up to 50,000 residential customers and 1,500 commercial and industrial customers were eligible to select alternative natural gas suppliers. By April 1, 1998, 3,200 residential customers (6 percent) and 915 commercial and industrial customers (61 percent) participated in the pilot program. The pilot program was recently expanded to encompass NIPSCO's entire service territory, making choice available to 610,000 residential customers and 50,000 commercial and industrial customers. Participation is limited to 150,000 residential customers and 20,000 commercial and industrial customers, however. Of NIPSCO's eligible customers, 6004 residential customers (4 percent) and 4,297 commercial and industrial customers (21 percent) were participating in the pilot program as of June 11, 1999.

The following gas marketers are participating qualified suppliers in the pilot program: NESI Integrated Energy Resources Inc. (a NIPSCO affiliate); NICOR Energy, LLC; Volunteer Energy Corporation, and Columbia Energy Services Corporation. Another supplier, WPS Energy Services, Inc., is qualified to provide service to pilot program participants but has not done so as yet. NIPSCO and its affiliate NESI serve 87 percent of residential customers and the majority of commercial customers. NIPSCO continues to educate ratepayers on the availability, benefits and mechanics of the Choice pilot program. The Company also continues its market research efforts to evaluate its own performance in communicating information on the Choice program, and gauging customers' reactions.

The Office of Utility Consumer Counselor has been actively involved in the customer education and program evaluation and modification phases of the Choice program. The OUCC provided materials to help consumers compare various alternative supplier options and programs.

2. NiSource Unsolicited Offer to Columbia Energy

On April 1, 1999, NiSource, the parent company of Northern Indiana Public Service Company, offered to buy Columbia Energy Group (Columbia), which is based in Herndon, Virginia. Columbia, one of nation's leading energy services companies, is involved in natural gas exploration, production, transmission, storage and distribution as well as propane and electric power generation, sales and trading. The company serves customers in thirty-four states and District of Columbia. In 1998, Columbia had revenues of nearly $6.6 billion and assets of approximately $7 billion.

NiSource withdrew the offer in anticipation of further merger discussions. On April 16, NiSource renewed its bid after Columbia cancelled the merger discussions. Columbia dismissed the offer, and made an unsuccessful bid for Consolidated Natural Gas, which rejected Columbia's offer in favor of its previously planned merger with Dominion Resources, Inc. On June 7, NiSource made an unsolicited buyout offer of $68 per share, or $5.7 billion, to Columbia. Columbia continued to refuse to schedule merger talks, and its board unanimously rejected the buyout, saying the company was not for sale.

On June 24, NiSource continued its hostile takeover attempt by appealing to Columbia's shareholders directly by making a tender offer for all of Columbia's outstanding common stock. Columbia advised its shareholders to take no action until the board reviewed the $68 per share offer and made a recommendation. NiSource stated that it would be willing to offer more than $68 per share if the Columbia Board cooperates and negotiates a definitive merger agreement with NiSource. On July 6, Columbia announced that it was once again rejecting NiSource's offer because the offer was inadequate.

NiSource, undeterred by Columbia's rejection, announced July 20, 1999, that with regard to its tender offer of Columbia Energy Group it has filed the necessary information under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 with the Federal Trade Commission and Department of Justice. The Act requires that parties to certain acquisitions of voting securities or assets notify the FTC and the DOJ and wait a specified period of time before consummating the transaction. The purpose of the Act is to ensure that such transactions receive meaningful scrutiny under the antitrust laws, with the possibility of an effective remedy for violations, prior to consummation.

3. ProLiance

ProLiance was formed by Citizens Gas and Indiana Gas in 1996 for the purpose of assuming the gas supply portfolio for the two utilities. In this capacity, ProLiance administers the utilities' pipeline transportation contracts, storage contracts and procures natural gas supplies for the two utilities. On March 29, 1996, twenty industrial customers of the utilities petitioned the Commission to disapprove the contracts between Indiana Gas and Citizens Gas relating to ProLiance. The petitioners were later joined by the OUCC. The CAC, NIPSCO, Louisville Gas & Electric and Panhandle Eastern Pipeline Company intervened in the case.

Among other concerns, the petitioners alleged that the contract between Indiana Gas and ProLiance should be disapproved as not in the public interest because of its adverse effect on competition.

In its order dated September 12, 1997, the IURC ruled that the agreements which created ProLiance are in the public interest, in part because of the efficiencies gained by consolidating the gas supplies of the two utilities.

The OUCC, CAC and the industrial customers appealed the decision. The Indiana Supreme Court heard oral arguments on the issue of transfer on Wednesday April 21, 1999. On April 22, 1999, the Supreme Court granted transfer of this appeal. As of July 26, 1999, no new action has been taken in the case.

G. State Competition Initiatives in Natural Gas

The gas industry has been competitive for years at the wholesale and large end-user level, as customers routinely purchase their gas supplies and other load-managing services in the marketplace. Increasingly choice options are also becoming available to residential and small commercial customers (See Appendix 4).

According to the Energy Information Administration, three states (New Mexico, New York and West Virginia) have statewide competition programs. Eight additional states (California, Colorado, Georgia, Maryland, Massachusetts, New Jersey, Ohio and Pennsylvania) are implementing statewide unbundling. Ten states (Deleware, Illinois, Indiana, Michigan, Montana, Nebraska, South Dakota, Virginia, Wisconsin and Wyoming) have pilot programs. Eleven states (Iowa, Kansas, Kentucky, Maine, Minnesota, Nevada, Hew Hampshire, Oklahoma, South Carolina, Texas and Vermont) do not have any pilot programs but are considering unbundling. Eighteen states have no pilot program and no action is planned.

V. FEDERAL LEGISLATIVE UPDATE

During the first six months of 1999, five electricity restructuring bills were introduced into Congress, including an amended comprehensive electricity competition plan from the Clinton administration and the Department of Energy. A comparison chart of all five bills is contained in Appendix 5.

The comprehensive plan is an updated version of the legislation presented to Congress last year. This year's version requires retail choice by January 1, 2003, unless a state opts out as a result of a public proceeding that finds consumers are better served under traditional rate-of-return regulation. As with the previous bill, the administration estimates consumers could save $20 billion annually, although a majority of the savings would come from a competitive wholesale market, not retail. The administration/DOE bill was introduced in the Senate by Senators Murkowski and Bingaman as S.1047, and in the House as H.R. 1828 by Rep. Bliley.

Other features of the Clinton/DOE plan include reciprocity requirements among states, recovery of verifiable stranded costs; repeal of the Public Utility Holding Company Act (PUHCA), repeal of Section 210 of the Public Utility Regulatory Policies Act (PURPA) that requires utilities to purchase from non-traditional generating sources; and renewable generation standards to encourage use of renewable energy. There are provisions that will subject federal power entities such as the Tennessee Valley Authority and the Bonneville Power Administration to FERC regulation for their transmission systems to foster development of regional transmission organizations. In addition, municipal utilities will lose tax-exempt status on any new bonds issued for generation and transmission facilities.

Four of the bills introduced this year give the FERC authority over unbundled retail transmission, and apply the FERC's open access rules to public power entities such as municipals, cooperatives and federal power authorities. All bills provide for state authority over stranded cost recovery, and four allow states to establish charges for universal service fees and public benefit programs. State jurisdiction over reciprocity requirements is featured in all five bills.

None of the bills introduced this year have advanced beyond committee yet. The three bills introduced into the House, the Burr, Stearns and Largent/Markey bills, were referred to the House Commerce Committee. The two Senate bills, sponsored by Senators Craig and Murkowski, were referred to the Senate Energy and Natural Resources Committee.

VI. EPA ACTIVITY

On October 27, 1998, the U.S. Environmental Protection Agency (EPA) published a final federal rule that requires each of 22 states in the eastern United States, including Indiana, to reduce emissions of nitrogen oxides significantly by 2007. Nitrogen oxides (NOX) are one precursor to ozone formation, and the federal rule is intended to reduce the transport of ozone and ozone pollutants that occurs in this multi-state region. The rule would require electric utilities to reduce NOX emissions by approximately 85 percent.

In May 1999, the Indiana Department of Environmental Management (IDEM) published its rulemaking to implement the EPA rule. Each state had a deadline of September 30, 1999, to develop a NOX reduction plan, or the EPA would impose its own plan to implement the rule. However, numerous parties (many of the 22 states and groups of utilities) have challenged EPA's rule in the District of Columbia U.S. Court of Appeals. In May 1999, in another case, a three- judge panel of this court first ruled that EPA may not have the legal authority to set new Clean Air Act standards for soot and smog. The panel then ruled that the 22 states in the NOX case do not have to meet the September 30, 1999, deadline for filing NOX reduction plans, and a stay of the rule was granted pending the outcome of the case. Oral arguments are expected to take place in the fall of 1999.

By July 1999, the pressure to develop a State Implementation Plan for NOX by September 30, 1999, was relieved, but IDEM is still pursuing the rule. Even if the EPA loses in court, there are existing regulations involving local nonattainment areas for ozone that will need to be addressed in Indiana. IDEM is set to provide a new deadline for comments on its rulemaking at a later date.

VII. RELIABILITY CONCERNS

A modern electric power system can be thought of as one large machine. All components are physically connected, and all can be dramatically affected by events elsewhere in the system. Although there are many devices to prevent them, blackouts can be triggered in a fraction of a second, causing serious damage to the power system and resulting in a loss of power to some areas for days. To help ensure system reliability, the industry has developed a high level of cooperation and coordination among private companies. With restructuring and competition forthcoming, the question now being debated is how electric utilities will maintain the high level of cooperation and coordination necessary for reliability while simultaneously providing greater access to the transmission system and competing for customers.

A. Electricity Capacity Status for the Summer of 1999

In May 1999, the IURC made an informal inquiry to Indiana's electric utilities to gather information on the electricity capacity status for the summer of 1999.[22] A review of the information provided by the utilities indicated that they had modified their electricity capacity strategies based on their experiences during the summer of 1998. For 1999, Indiana utilities planned maintenance so that it would be completed before the summer peaking season, arranged power purchases to help limit exposure to potentially high spot market prices and spread their purchases among more suppliers to limit possible problems from the default or curtailment by a power supplier.

Reports from the reliability regions of ECAR and MAIN, which were issued prior to the 1999 summer season, also suggested that the regional capacity situation was better this summer than last. ECAR projected a 10.8 percent capacity margin, even accounting for the Cook nuclear units remaining offline. This was a 1.5 percent increase from 1998. MAIN projected improved capacity margins over 1998 due to the availability of nuclear plants, additional generation in the region and transmission system upgrades.

During July 1999, throughout the Midwest utilities' generation capacity was stretched to its limits due to successive days of temperatures in the mid- and upper-90s and heat indexes over 100. This prompted many utilities in the region, including all of Indiana's electricity-supplying utilities,

[22] IPL, AEP/I&M, PSI, NIPSCO, SIGECO, IMPA, HE and WVPA.

to request voluntary conservation by the public to help reduce the possibility of rolling blackouts. A rolling blackout is a situation where the utility cuts off electricity to a geographical segment of its customers in order to maintain the stability of the electric system, as a whole. The outages are rotated through segments of the utility's system for specific periods of time so that no single group of customers is inconvenienced by the outage.

This event highlights the serious decline in generation capacity reserves over the past few years. The following graph illustrates the decline in the capacity margin for the state of Indiana between 1987 and 1998.

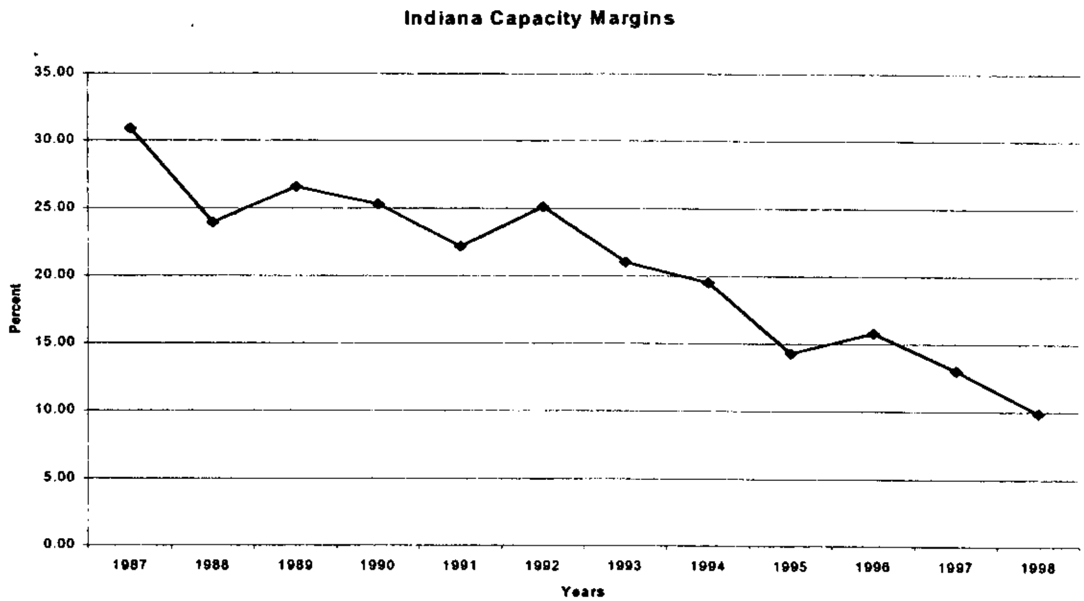
The capacity margin can be thought of as the "safety net" of generation capacity that is in excess of what is needed to meet the peak load. The capacity margin is necessary to allow for contingencies such as planned and unplanned outages of generation units, extreme weather conditions and other reliability considerations. In 1987 the capacity margin for Indiana was over 30% but it declined to less than 10% by 1998.

Utilities, unsure if or when industry restructuring will occur, have been reluctant to invest in new generation capacity for fear of being left with stranded costs. The lack of new generation construction by utilities, coupled with a consistent load growth of roughly 2% per year over the last several years, has resulted in the erosion of capacity margin.

In April 1999, the IURC approved a settlement agreement signed by Indianapolis Power & Light (IPL), the Office of Utility Consumer Counselor, Citizens Action Coalition of Indiana, Inc. and a group of IPL industrial customers that would allow IPL to construct up to 200 MW of combustion turbine power generation.[23] The settlement deferred any determination regarding ratemaking issues until a later date and allowed IPL to recover fuel costs through the FAC when the unit was used for jurisdictional retail purposes.

Recently, AES Greenfield, Duke Energy Vermillion and Enron Capital and Trade Resources, three independent power producers, proposed several merchant power plants to be built in Indiana. If completed, these plants would provide approximately 1500 MW of new generation. Merchant plants are built to sell power to the wholesale market so there is no guarantee that the electricity produced by these plants would go to Indiana consumers. These projects, combined with the IPL project, should help improve the capacity margin region-wide. For a further discussion of these projects, see Section IV.B.2 of this report.

[23] Cause No. 41337. Order issued April 7, 1999.



B. North American Electric Reliability Council

The North American Electric Reliability Council (NERC), the voluntary industry group that oversees reliability concerns at the present time, has been studying the issues of who will provide reliability in the future and how this will be accomplished. In 1997, NERC formed a blue ribbon panel of outside experts to perform a study and recommend a new structure for itself. This panel issued a report in December 1997.[24] On July 9, 1998, the NERC Board of Trustees approved a series of recommendations that will reform it into the North American Electric Reliability Organization (NAERO), a new self-regulating reliability organization. The transition began in January 1999 when nine independent members were elected to the NERC Board. This expanded, more independent Board will govern NERC until:

- U.S. and Canadian governments provide for appropriate grants of authority to a self-regulating reliability organization (SRRO) to set standards, enforce compliance, and collect funds (with a similar grant of authority from the government of Mexico to follow)

- NAERO applies for and is approved as the only SRRO by the appropriate regulatory authorities in the U.S. and Canada

- Funding of NAERO is decoupled from the Regional Reliability Councils.

[24] Reliable Power: Renewing the North American Electric Reliability Oversight System, NERC Electric Reliability Panel, December 22, 1997.

After these conditions are satisfied, all but the nine independent members of the Board will step down and NAERO will be governed by an all-independent Board. The current Board also approved the following membership guidelines:

- System operator organizations (including control areas, ISOs, and security coordinators) and the Regional Reliability Organization in which they operate are required to become members of NAERO

- All organizations that have either a direct physical or commercial interaction with the bulk electric system may become members of NAERO

- Public interest groups may become members of NAERO

- Government regulators may be nonvoting members of NAERO.

Membership in NAERO provides the opportunity to serve on one of its committees and to vote for the independent directors.[25]

[25] This information is taken from Highlights and Summary of Action, Board of Trustees Meeting, North American Electric Reliability Council, July 9-10, 1998, Chicago, IL.

VIII. ACKNOWLEDGEMENTS

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IX. ACRONYMS

ARP – Alternative Regulatory Plan
CAC – Citizens Action Coalition
CPU – California Public Utility Commission
DOE – Department of Energy
DSM – Demand-Side Management
FERC – Federal Energy Regulatory Commission
G&T – Generation and Transmission
GCIM – Gas Cost Incentive Mechanism
I&M – Indiana Michigan Power Company, subsidiary of AEP
ICC – Illinois Commerce Commission
IMPA – Indiana Municipal Power Agency
IOU – Investor-owned Utility
IPL – Indianapolis Power and Light
IRP – Integrated Resource Plan
ISO – Independent System Operator
IURC – Indiana Utility Regulatory Commission
kWh – Kilowatt Hour
LDC – Local Distribution Company (gas)
MPSC – Michigan Public Service Commission
NERC – North American Electric Reliability Council
NHPUC – New Hampshire Public Utility Commission
NIPSCO – Northern Indiana Public Service Company
OUCC – Office of Utility Consumer Counselor
PPUC – Pennsylvania Public Utility Commission
PSI – PSI Energy
PSNH – Public Service New Hampshire
PUHCA – Public Utility Holding Company Act 1935
PURPA – Public Utility Regulatory Policies Act 1978
PX – Power Exchange
REMC – Rural Electric Membership Cooperative
SEC – Securities and Exchange Commission
SIGECO – Southern Indiana Gas & Electric Company
SOLR – Supplier of Last Resort
T&D – Transmission and Distribution

X. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Aggregator: An entity that pools customers into a buying group for the purchase of a commodity good or service.

Alternative Regulatory Plan (ARP): In contrast to cost-of-service regulation, alternative regulatory plans are designed to allow the utility more flexibility in pricing energy to customers. ARPs may also contain provisions to streamline the regulatory approval process.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Citygate: A point of delivery to the gas local distribution company from the pipeline.

Convergence Mergers: In the context of energy, mergers between gas and electric utilities.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service: A term related to the current methods of regulating utilities (both gas and electric). A cost-of-service study analyzes a utility's average costs (also called embedded costs) of facilities and expenses in relationship to its revenues to determine rates (prices) for the customer. This is generally referred to as cost-of-service ratemaking or cost-of-service pricing.

Dekatherm (Dth): A unit of heating value equivalent to 1 million Btus.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Earnings Test: An evaluation conducted as part of generating fuel cost adjustments and all gas cost adjustments to determine if the proposed change in fuel or gas costs would result in a utility earning in excess of its allowed net operating income. The actual evaluation is complex, but if the utility is found to be earning more than allowed, the excess revenue is returned to the ratepayers.

Gas Cost Adjustment (GCA): A formal and summary proceeding held quarterly or semi-annually by the IURC for natural gas utilities which allows these utilities to increase or decrease rates based on changes in the price of gas purchased from various sources. Rates are projected for three or six months into the future and "reconciled" from the past with costs from comparable time periods and an "earnings test" is part of the process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Gigawatt-Hour (GWh): One gigawatt of generation for one hour.

Green Power: Term used to describe electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Local Distribution Company (LDC): The utility that is responsible for delivering gas to the customer behind the citygate (where the pipeline delivers gas to the LDC).

Megawatt (MW): One thousand kilowatts or one million watts.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America, including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Power Exchange: An independent entity with no affiliate or financial interest in distribution, transmission or generation companies or facilities. It would match bids submitted by utilities, power marketers, brokers and other participants ranking the bids on a least-cost basis and arrange for the power to be delivered.

Power Marketers: A business entity engaged in buying and selling electricity, but does not own generation or transmission facilities. Power marketers take ownership of the electricity and offer risk management derivative products such as options, swaps, forward contracts and electricity futures.

Public Utility Holding Company Act of 1935 (PUCHA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state or presumed to be susceptible to effective state regulation are "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Registered Holding Company: Any company that acquires more than 10 percent of the equity of a utility and as a consequence, must register with the Securities and Exchange Commission and is subject to all provisions of PUHCA.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative regulatory plans, among other things.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Shopping Credit: A credit given to an electric utility customer that chooses to purchase electricity from a supplier other than the incumbent utility. The shopping credit generally reflects the cost of generation that is saved by the incumbent by the customer purchasing electricity from an alternative supplier.

Stranded Costs: Costs associated with assets that prove to be uneconomical in a competitive environment. Because these assets were previously approved by regulatory authorities and included in rates, utilities claim they should be able to fully recover these costs before the transition to customer choice is completed.

Supplier of Last Resort: In a customer choice market, the supplier of last resort will be a designated power supplier that will provide the energy needs of customer who can't or won't choose a supplier.

Thirty-Day Filings: Requests for utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. This process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less costly manner than a formally docketed case.

Throughput (Gas): Actual or estimated volume of natural gas that may be carried on a pipeline over a period of time.

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Transportation (Gas): The transportation of natural gas by a pipeline (upstream of the citygate) and/or by the LDC (behind the citygate).

Unbundling: The process of separating out the package of services offered by an electric or gas company and charging separate rates for each service that fairly represents the cost of providing the service. In the electric industry, these may include: transmission, generation, distribution services, metering, billing, maintenance. In the natural gas industry, in addition to transportation of gas, unbundling may include storage, gathering, balancing services and other items.

Universal Service: A condition that makes a utility service (gas, electricity, telephone, etc.) available to any customer that wants it, at an affordable price.

Vertically Integrated Utilities (companies): An arrangement whereby the same company owns most or all of the facilities necessary for producing, transporting and selling electricity (or gas). Traditionally, vertically integrated electric utilities have owned the generation, transmission and distribution facilities. In some cases, electric utilities have also owned coal mines and gas supplies to increase the level of vertical integration.

XI. APPENDICES

Sales, Revenues and Market Share for Indiana Electric Utilities
1998 Summary

kWh

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	20,923,228,000	17,082,200,000	36,690,041,000	58,442,867,000	133,138,336,000
Rural Electric Membership Corporations	1,751,068,499	1,265,341,118	-	8,101,951	3,024,511,568
Municipal Electric Utilities	1,506,375,140	3,640,692,821	-	87,942,093	5,235,010,054
Totals	24,180,671,639	21,988,233,939	36,690,041,000	58,538,911,044	141,397,857,622

Revenues

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	$ 1,493,099,901	$ 1,058,880,965	$ 1,550,368,638	$ 1,753,292,593	$ 5,855,642,097
Rural Electric Membership Corporations	119,749,715	36,936,175	-	2,398,752	159,084,642
Municipal Electric Utilities	89,807,590	168,907,979	-	31,533,643	290,249,212
Totals	$ 1,702,657,206	$ 1,264,725,119	$ 1,550,368,638	$ 1,787,224,988	$ 6,304,975,951

Retail Market Share By kWh

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	86.53%	77.69%	100.00%	99.84%	94.16%
Rural Electric Membership Corporations	7.24%	5.75%	-	0.01%	2.14%
Municipal Electric Utilities	6.23%	16.56%	-	0.15%	3.70%

Retail Market Share By Revenues

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	87.69%	83.72%	100.00%	98.10%	92.87%
Rural Electric Membership Corporations	7.03%	2.92%	-	0.13%	2.52%
Municipal Electric Utilities	5.27%	13.36%	-	1.76%	4.60%

Investor-Owned Electric Utilities
1998 Data

kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	5,133,902,000	4,539,435,000	7,754,736,000	7,856,465,000	25,284,538,000
2	Indianapolis Power & Light Company	4,320,065,000	1,872,792,000	7,095,239,000	2,352,753,000	15,640,849,000
3	Northern Indiana Public Service Company	2,936,762,000	3,162,511,000	8,794,481,000	2,168,223,000	17,061,977,000
4	PSI Energy, Inc.	7,206,474,000	6,264,132,000	10,789,469,000	44,031,714,000	68,291,789,000
5	Southern Indiana Gas & Electric Company	1,326,025,000	1,243,330,000	2,256,116,000	2,033,712,000	6,859,183,000
	Totals	**20,923,228,000**	**17,082,200,000**	**36,690,041,000**	**58,442,867,000**	**133,138,336,000**

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	$ 374,392,301	$ 290,149,221	$ 370,328,758	$ 328,620,075	$ 1,363,490,355
2	Indianapolis Power & Light Company	269,351,310	122,082,394	321,102,936	60,830,451	773,367,091
3	Northern Indiana Public Service Company	290,738,089	267,995,588	405,302,470	90,585,818	1,054,621,965
4	PSI Energy, Inc.	470,152,004	312,107,978	378,569,745	1,210,505,991	2,371,335,718
5	Southern Indiana Gas & Electric Company	88,466,197	66,545,784	75,064,729	62,750,258	292,826,968
	Totals	**$ 1,493,099,901**	**$1,058,880,965**	**$ 1,550,368,638**	**$ 1,753,292,593**	**$ 5,855,642,097**

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
1	Indiana Michigan Power Company	$0.07	$0.06	$0.05	$0.04	$0.05
2	Indianapolis Power & Light Company	0.06	0.07	0.05	0.03	0.05
3	Northern Indiana Public Service Company	0.10	0.08	0.05	0.04	0.06
4	PSI Energy, Inc.	0.07	0.05	0.04	0.03	0.03
5	Southern Indiana Gas & Electric Company	0.07	0.05	0.03	0.03	0.04

Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	
1	Indiana Michigan Power Company	27.46%	21.28%	27.16%	24.10%	
2	Indianapolis Power & Light Company	34.83%	15.79%	41.52%	7.87%	
3	Northern Indiana Public Service Company	27.57%	25.41%	38.43%	8.59%	
4	PSI Energy, Inc.	19.83%	13.16%	15.96%	51.05%	
5	Southern Indiana Gas & Electric Company	30.21%	22.73%	25.63%	21.43%	

Rural Electric Membership Corporations
1998 Data
kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Fulton County R.E.M.C.	61,047,585	12,270,222	2,725,905	76,043,712
2.	Harrison County R.E.M.C.	259,935,140	125,787,715	2,011,753	387,734,608
3.	Jackson County R.E.M.C.	305,423,024	64,395,830	58,180	369,877,034
4.	Jay County R.E.M.C.	73,484,275	17,112,514	-	90,596,789
5.	Johnson County R.E.M.C.	177,587,085	66,980,898	361,855	244,929,838
6.	Marshall County R.E.M.C.	59,838,718	14,164,560	844,060	74,847,338
7.	Newton County R.E.M.C.	15,051,336	8,423,709	238,824	23,713,869
8.	Northeastern R.E.M.C.	236,789,913	178,454,735	805,443	416,050,091
9.	Orange County R.E.M.C.				-
10.	Southeastern Indiana R.E.M.C.	290,657,701	656,497,726	-	947,155,427
11.	Utilities District of Western Indiana R.E.M.C.	201,192,010	61,848,757	-	263,040,767
12.	Wabash County R.E.M.C.	70,061,712	59,404,452	1,055,931	130,522,095
	Totals	**1,751,068,499**	**1,265,341,118**	**8,101,951**	**3,024,511,568**

Rural Electric Membership Corporations

1998 Data

Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Fulton County R.E.M.C.	$ 4,103,398	$ 810,429	$ 261,445	$ 5,175,272
2.	Harrison County R.E.M.C.	16,428,013	5,917,601	494,141	22,839,755
3.	Jackson County R.E.M.C.	20,623,165	3,914,913	402,968	24,941,046
4.	Jay County R.E.M.C.	5,049,614	1,124,225	49,928	6,223,767
5.	Johnson County R.E.M.C.	12,889,519	3,888,040	207,303	16,984,862
6.	Marshall County R.E.M.C.	5,020,833	993,235	145,941	6,160,009
7.	Newton County R.E.M.C.	1,086,339	527,418	25,999	1,639,756
8.	Northeastern R.E.M.C.	15,764,843	9,360,940	139,723	25,265,506
9.	Orange County R.E.M.C.				-
10.	Southeastern Indiana R.E.M.C.	20,545,057	4,055,648	268,456	24,869,161
11.	Utilities District of Western Indiana R.E.M.C.	13,569,441	3,364,769	246,663	17,180,873
12.	Wabash County R.E.M.C.	4,669,493	2,978,957	156,185	7,804,635
	Totals	**$ 119,749,715**	**$ 36,936,175**	**$ 2,398,752**	**$ 159,084,642**

Rural Electric Membership Corporations

1998 Data

Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Fulton County R.E.M.C.	$ 0.07	$ 0.07	$ 0.10	$ 0.07
2.	Harrison County R.E.M.C.	0.06	0.05	0.25	0.06
3.	Jackson County R.E.M.C.	0.07	0.06	6.93	0.07
4.	Jay County R.E.M.C.	0.07	0.07	-	0.07
5.	Johnson County R.E.M.C.	0.07	0.06	0.57	0.07
6.	Marshall County R.E.M.C.	0.08	0.07	0.17	0.08
7.	Newton County R.E.M.C.	0.07	0.06	0.11	0.07
8.	Northeastern R.E.M.C.	0.07	0.05	0.17	0.06
9.	Orange County R.E.M.C.	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
10.	Southeastern Indiana R.E.M.C.	0.07	0.01	-	0.03
11.	Utilities District of Western Indiana R.E.M.C.	0.07	0.05	-	0.07
12.	Wabash County R.E.M.C.	0.07	0.05	0.15	0.06

Rural Electric Membership Corporations

1998 Data

Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1.	Fulton County R.E.M.C.	79.29%	15.66%	5.05%
2.	Harrison County R.E.M.C.	71.93%	25.91%	2.16%
3.	Jackson County R.E.M.C.	82.69%	15.70%	1.62%
4.	Jay County R.E.M.C.	81.13%	18.06%	0.80%
5.	Johnson County R.E.M.C.	75.89%	22.89%	1.22%
6.	Marshall County R.E.M.C.	81.51%	16.12%	2.37%
7.	Newton County R.E.M.C.	66.25%	32.16%	1.59%
8.	Northeastern R.E.M.C.	62.40%	37.05%	0.55%
9.	Orange County R.E.M.C.	#DIV/0!	#DIV/0!	#DIV/0!
10.	Southeastern Indiana R.E.M.C.	82.61%	16.31%	1.08%
11.	Utilities District of Western Indiana R.E.M.C.	78.98%	19.58%	1.44%
12.	Wabash County R.E.M.C.	59.83%	38.17%	2.00%

Municipal Electric Utilities
1998 Data
kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Anderson Municipal Light & Power	304,153,619	401,217,573	4,780,341	710,151,533
2.	Auburn Municipal Electric	50,649,371	464,674,707	-	515,324,078
3.	Bargersville Municipal Power & Light	25,781,107	17,644,859	1,734,525	45,160,491
4.	Boonville Municipal Light & Power	29,608,366	34,494,747	-	64,103,113
5.	Centerville Municipal Power & Light	14,332,174	7,062,631	1,391,343	22,786,148
6.	Columbia City Municipal Electric	32,129,532	73,512,222	2,551,188	108,192,942
7.	Covington Municipal Electric	12,955,596	11,051,638	-	24,007,234
8.	Crawfordsville Municipal Electric Light & Power	72,762,351	312,999,571	14,005,856	399,767,778
9.	Edinburgh Municipal Electric	21,716,774	64,843,149	1,008,446	87,568,369
10.	Frankfort City Light & Power	70,052,058	255,015,908	3,051,858	328,119,824
11.	Frankton Municipal Electric	16,968,016	-	-	16,968,016
12.	Garrett Municipal Electric	62,501,925	-	-	62,501,925
13.	Greenfield Municipal Electric	53,480,279	167,334,453	2,748,302	223,563,034
14.	Kingsford Heights Municipal Electric	4,965,571	-	-	4,965,571
15.	Knightstown Municipal Electric	12,213,701	8,920,515	678,652	21,812,868
16.	Lawrenceburg Municipal Electric	24,489,326	68,788,185	1,080,360	94,357,871
17.	Lebanon Municipal Electric	57,362,338	101,069,108	2,777,392	161,208,838
18.	Logansport Municipal Electric	93,477,063	279,258,953	2,617,206	375,353,222
19.	Mishawaka Municipal Electric	162,827,858	351,906,387	22,670,402	537,404,647
20.	Paoli Municipal Electric	-	-	-	-
21.	Peru Municipal Electric Light & Power	86,360,879	127,113,109	4,733,747	218,207,735
22.	Richmond Municipal Power & Light	188,376,981	722,421,755	10,674,300	921,473,036
23.	South Whitley Municipal Electric	8,196,216	11,421,877	1,179,207	20,797,300
24.	Straughn Municipal Electric	1,309,065	-	-	1,309,065
25.	Tipton Municipal Electric	33,679,401	69,082,495	1,023,641	103,785,537
26.	Troy Municipal Electric	-	-	-	-
27.	Washington City Municipal Light & Power	66,025,573	90,858,979	9,235,327	166,119,879
	Totals	**1,506,375,140**	**3,640,692,821**	**87,942,093**	**5,235,010,054**

Municipal Electric Utilities
1998 Data
Revenues

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Anderson Municipal Light & Power	$ 16,867,324	$ 18,559,525	$ 774,046	$ 36,200,895
2.	Auburn Municipal Electric	2,567,938	22,270,887	611,197	25,450,022
3.	Bargersville Municipal Power & Light	1,212,597	1,080,617	137,476	2,430,690
4.	Boonville Municipal Light & Power	2,144,305	2,199,293	91,920	4,435,518
5.	Centerville Municipal Power & Light	545,562	456,034	71,523	1,073,119
6.	Columbia City Municipal Electric	1,939,306	3,949,198	192,089	6,080,593
7.	Covington Municipal Electric	753,489	614,383	85,015	1,452,887
8.	Crawfordsville Municipal Electric Light & Power	4,286,475	12,770,393	2,461,471	19,518,339
9.	Edinburgh Municipal Electric	1,169,263	3,234,527	66,861	4,470,651
10.	Frankfort City Light & Power	3,889,577	9,851,907	481,165	14,222,649
11.	Frankton Municipal Electric	876,208	-	125,197	1,001,405
12.	Garrett Municipal Electric	3,620,457	-	277,810	3,898,267
13.	Greenfield Municipal Electric	2,785,009	6,937,869	432,658	10,155,536
14.	Kingsford Heights Municipal Electric	267,243	98,052	60,032	425,327
15.	Knightstown Municipal Electric	651,238	483,449	37,403	1,172,090
16.	Lawrenceburg Municipal Electric	1,276,167	3,377,198	170,928	4,824,293
17.	Lebanon Municipal Electric	3,201,553	4,914,230	118,232	8,234,015
18.	Logansport Municipal Electric	6,378,697	14,881,377	312,381	21,572,455
19.	Mishawaka Municipal Electric	13,678,604	19,687,769	2,156,032	35,522,405
20.	Paoli Municipal Electric	782,200	1,508,981	111,939	2,403,120
21.	Peru Municipal Electric Light & Power	4,639,305	5,350,977	310,161	10,300,443
22.	Richmond Municipal Power & Light	10,228,899	28,658,276	21,659,582	60,546,757
23.	South Whitley Municipal Electric	443,291	617,720	63,843	1,124,854
24.	Straughn Municipal Electric	73,304	8,878	8,383	90,565
25.	Tipton Municipal Electric	1,760,043	3,153,860	91,209	5,005,112
26.	Troy Municipal Electric	222,580	332,753	62,338	617,671
27.	Washington City Municipal Light & Power	3,546,956	3,909,826	562,752	8,019,534
	Totals	**$89,807,590**	**$168,907,979**	**$31,533,643**	**$290,249,212**

Municipal Electric Utilities
1998 Data
Average Rate Per kWh

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
1.	Anderson Municipal Light & Power	$0.06	$0.05	$0.16	$0.05
2.	Auburn Municipal Electric	0.05	0.05	-	0.05
3.	Bargersville Municipal Power & Light	0.05	0.06	0.08	0.05
4.	Boonville Municipal Light & Power	0.07	0.06	-	0.07
5.	Centerville Municipal Power & Light	0.04	0.06	0.05	0.05
6.	Columbia City Municipal Electric	0.06	0.05	0.08	0.06
7.	Covington Municipal Electric	0.06	0.06	-	0.06
8.	Crawfordsville Municipal Electric Light & Power	0.06	0.04	0.18	0.05
9.	Edinburgh Municipal Electric	0.05	0.05	-	0.05
10.	Frankfort City Light & Power	0.06	0.04	0.16	0.04
11.	Frankton Municipal Electric	0.05	-	-	0.06
12.	Garrett Municipal Electric	0.06	-	-	0.06
13.	Greenfield Municipal Electric	0.05	0.04	0.16	0.05
14.	Kingsford Heights Municipal Electric	0.05	-	-	0.09
15.	Knightstown Municipal Electric	0.05	0.05	0.06	0.05
16.	Lawrenceburg Municipal Electric	0.05	0.05	0.16	0.05
17.	Lebanon Municipal Electric	0.06	0.05	0.04	0.05
18.	Logansport Municipal Electric	0.07	0.05	0.12	0.06
19.	Mishawaka Municipal Electric	0.08	0.06	0.10	0.07
20.	Paoli Municipal Electric	-	-	-	-
21.	Peru Municipal Electric Light & Power	0.05	0.04	0.07	0.05
22.	Richmond Municipal Power & Light	0.05	0.04	2.03	0.07
23.	South Whitley Municipal Electric	0.05	0.05	0.05	0.05
24.	Straughn Municipal Electric	0.06	-	-	0.07
25.	Tipton Municipal Electric	0.05	0.05	0.09	0.05
26.	Troy Municipal Electric	-	-	-	-
27.	Washington City Municipal Light & Power	0.05	0.04	0.06	0.05

Municipal Electric Utilities
1998 Data
Retail Market Share

	UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
1.	Anderson Municipal Light & Power	46.59%	51.27%	2.14%
2.	Auburn Municipal Electric	10.09%	87.51%	2.40%
3.	Bargersville Municipal Power & Light	49.89%	44.46%	5.66%
4.	Boonville Municipal Light & Power	48.34%	49.58%	2.07%
5.	Centerville Municipal Power & Light	50.84%	42.50%	6.66%
6.	Columbia City Municipal Electric	31.89%	64.95%	3.16%
7.	Covington Municipal Electric	51.86%	42.29%	5.85%
8.	Crawfordsville Municipal Electric Light & Power	21.96%	65.43%	12.61%
9.	Edinburgh Municipal Electric	26.15%	72.35%	1.50%
10.	Frankfort City Light & Power	27.35%	69.27%	3.38%
11.	Frankton Municipal Electric	87.50%	0.00%	12.50%
12.	Garrett Municipal Electric	92.87%	0.00%	7.13%
13.	Greenfield Municipal Electric	27.42%	68.32%	4.26%
14.	Kingsford Heights Municipal Electric	62.83%	23.05%	14.11%
15.	Knightstown Municipal Electric	55.56%	41.25%	3.19%
16.	Lawrenceburg Municipal Electric	26.45%	70.00%	3.54%
17.	Lebanon Municipal Electric	38.88%	59.68%	1.44%
18.	Logansport Municipal Electric	29.57%	68.98%	1.45%
19.	Mishawaka Municipal Electric	38.51%	55.42%	6.07%
20.	Paoli Municipal Electric	32.55%	62.79%	4.66%
21.	Peru Municipal Electric Light & Power	32.55%	62.79%	4.66%
22.	Richmond Municipal Power & Light	45.04%	51.95%	3.01%
23.	South Whitley Municipal Electric	39.41%	54.92%	5.68%
24.	Straughn Municipal Electric	80.94%	9.80%	9.26%
25.	Tipton Municipal Electric	35.16%	63.01%	1.82%
26.	Troy Municipal Electric	36.04%	53.87%	10.09%
27.	Washington City Municipal Light & Power	44.23%	48.75%	7.02%

ANALYSIS OF GAS SALES DATA
FOR 1996, 1997, AND 1998

CITIZENS GAS AND COKE UTILITY

	1998	1997	1996
Total Sales By Class (Dth)			
Residential	21,471,821	26,392,624	28,483,330
Commercial	11,033,572	14,934,080	17,041,493
Industrial	2,498,354	6,923,412	8,313,991
Other	(506,300)	374,100	2,939,050
Total	34,497,447	48,624,216	56,777,864
Total Transportation By Class (Dth)			
Residential		-	-
Commercial		2,168,530	929,276
Industrial		6,976,993	5,084,490
Other		-	163,656
Total	-	9,145,523	6,177,422
Total Throughput By Class (Dth)			
Residential		26,392,624	28,483,330
Commercial		17,102,610	17,970,769
Industrial		13,900,405	13,398,481
Other		374,100	3,193,406
Total	-	57,769,739	63,045,986
Percent Transportation to Throughput			
Residential	0.00%	0.00%	0.00%
Commercial	#DIV/0!	12.68%	5.17%
Industrial	#DIV/0!	50.19%	37.95%
Other	#DIV/0!	0.00%	5.12%
Total	#DIV/0!	15.83%	9.80%

INDIANA GAS COMPANY, INC.

	1998	1997	1996
Total Sales By Class (Dth)			
Residential	38,370,246	48,208,746	48,866,563
Commercial	15,412,876	19,435,857	19,778,149
Industrial	8,722,021	13,499,071	20,305,734
Other			-
Total	62,505,143	81,143,674	88,950,446
Total Transportation By Class (Dth)			
Residential		-	-
Commercial		-	-
Industrial		42,778,546	36,048,401
Other		-	-
Total	-	42,778,546	36,048,401
Total Throughput By Class (Dth)			
Residential		48,208,746	48,866,563
Commercial		19,435,857	19,778,149
Industrial		56,277,617	56,354,135
Other		-	-
Total	-	123,922,220	124,998,847
Percent Transportation to Throughput			
Residential	0.00%	0.00%	0.00%
Commercial	0.00%	0.00%	0.00%
Industrial	#DIV/0!	76.01%	63.97%
Other	0.00%	0.00%	0.00%
Total	#DIV/0!	34.52%	28.84%

ANALYSIS OF GAS SALES DATA
FOR 1996, 1997, AND 1998

NORTHERN INDIANA PUBLIC SERVICE CO.	1998	1997	1996
Total Sales By Class (Dth)			
Residential	58,346,000	73,452,000	77,050,000
Commercial	22,303,000	29,050,000	29,401,000
Industrial	11,897,000	15,807,000	16,528,000
Other	22,795,000	13,887,000	7,922,000
Total	115,341,000	132,196,000	130,901,000
Total Transportation By Class (Dth)			
Residential	207,000	-	-
Commercial	5,384,000	3,957,000	3,740,000
Industrial	167,648,000	156,484,000	151,446,000
Other	-	-	-
Total	173,239,000	160,441,000	155,186,000
Total Throughput By Class (Dth)			
Residential	58,553,000	73,452,000	77,050,000
Commercial	27,687,000	33,007,000	33,141,000
Industrial	179,545,000	172,291,000	167,974,000
Other	22,795,000	13,887,000	7,922,000
Total	288,580,000	292,637,000	286,087,000
Percent Transportation to Throughput			
Residential	0.35%	0.00%	0.00%
Commercial	19.45%	11.99%	11.29%
Industrial	93.37%	90.83%	90.16%
Other	0.00%	0.00%	0.00%
Total	60.03%	54.83%	54.24%

SOUTHERN INDIANA GAS AND ELECTRIC CO	1998	1997	1997
Total Sales By Class (Dth)			
Residential	7,924,707	9,653,802	10,435,599
Commercial	3,401,010	4,367,755	5,174,821
Industrial	513,612	998,799	2,667,594
Other	(223,594)	(194,892)	985,306
Total	11,615,735	14,825,464	19,263,320
Total Transportation By Class (Dth)			
Residential	-	-	-
Commercial	1,361,490	781,909	268,144
Industrial	14,305,752	12,989,812	11,049,737
Other	1,681,794	772,338	483,495
Total	17,349,036	14,544,059	11,801,376
Total Throughput By Class (Dth)			
Residential	7,924,707	9,653,802	10,435,599
Commercial	4,762,500	5,149,664	5,442,965
Industrial	14,819,364	13,988,611	13,717,331
Other	1,458,200	577,446	1,468,801
Total	28,964,771	29,369,523	31,064,696
Percent Transportation to Throughput			
Residential	0.00%	0.00%	0.00%
Commercial	28.59%	15.18%	4.93%
Industrial	96.53%	92.86%	80.55%
Other	115.33%	133.75%	32.92%
Total	59.90%	49.52%	37.99%

CITIZENS GAS, INDIANA GAS, NIPSCO AND SIGECO COMBINED
ANALYSIS OF GAS SALES DATA

	1998	1997	1996
Total Sales By Class (1,000 Dth)			
Residential	126,113	157,707	164,835
Commercial	52,150	67,788	71,395
Industrial	23,631	37,228	47,815
Other	22,065	14,066	11,846
Total	223,959	276,789	295,893
Total Transportation By Class (1,000 Dth)			
Residential	207	-	-
Commercial	6,745	6,907	4,937
Industrial	181,954	219,229	203,629
Other	1,682	772	647
Total	190,588	226,909	209,213
Total Throughput By Class (1,000 Dth)			
Residential	66,478	157,707	164,835
Commercial	32,450	74,695	76,333
Industrial	194,364	256,458	251,444
Other	24,253	14,839	12,584
Total	317,545	503,698	505,197
Percent Transportation to Throughput			
Residential	0.31%	0.00%	0.00%
Commercial	20.79%	9.25%	6.47%
Industrial	93.61%	85.48%	80.98%
Other	6.93%	5.20%	5.14%
Total	60.02%	45.05%	41.41%

1999 Restructuring Activities by State

Alabama - Alabama Power and other public utilities in the state have urged the Public Service Commission to take no immediate action to restructure the state's electric industry. At the same time a coalition of industrial users has proposed that the state initiate retail choice by January 1, 2002, and completes the transition by December 31, 2004.

The Alabama Public Service Commission opened an inquiry into restructuring in June 1998. It is in the process of developing a policy statement on retail competition but is not expected to issue an actual restructuring plan in the near future.

Alaska - On April 5, 1999, CH2M Hill and Econergy International Corporation presented a joint report on electric utility restructuring in Alaska to the Alaska Public Utilities Commission and the State Legislature. Some of the recommendations in the report include:

- Continued and expanded efforts to improve rural system efficiencies through aggregation of administration, fuel purchasing, operations, logistical and other appropriate functions among geographically separate but proximate villages.
- In order to build experience in the use and deployment of distributed energy systems, which offer potential long-term cost savings, consider the creation of a pilot program based on technology demonstration and deployment conducted in coordination with government and non-government organizations.
- Initiate a specific set of market-friendly regulatory reforms in order to bring the real competitive opportunity into focus.

Arizona - Arizona's two largest electric utilities; Tucson Electric Power Company (TEP) and Arizona Public Service (APS), have filed settlement agreements with the Arizona Corporation Commission that would allow electricity supply competition by the end of 1999.

The TEP settlement would initiate electricity supply competition in the third quarter of 1999. Retail customers would receive a 1% base price discount on both July 1, 1999, and July 1, 2000 followed by a price freeze through 2008. The agreement also calls for TEP's full recovery of all regulatory assets and generation-related stranded costs with no net write-offs. These costs would be recovered through a competition transition charge that would remain in effect until December 31, 2008.

The APS settlement would begin competition as early as August 1999. Residential and small commercial customers will receive a total reduction of 7.5% in electricity prices between 1999 and 2003 – an average of 1.5% annually. Customers with demands of 3 MWs or more will get a 5% reduction between 1999 and 2002. APS will be allowed to recovery $350 million of its estimated $533 million in stranded costs through a competition transition charge that will remain in effect through 2005.

Arkansas - The Arkansas Legislature on April 8, 1999, passed a major restructuring bill (SB 791), which calls for the start of retail choice as early as 2002. It is expected that Governor Mike Huckabee will sign the measure.

The bill provides that s mall users should receive a standard offer from their utilities at current rate levels for three years after competition starts.

It also requires that utilities file a market power analysis before choice begins.

In general the bill orders the Arkansas Public Service Commission (PSC) to begin retail choice for all users on January 1, 2002, but it can delay the start up to January 1, 2003, if the PSC decided the utilities are not ready. The bill gives the PSC power to control market power but not to force asset divestiture except in extreme cases. The PSC also has wide powers to determine stranded costs and set transition charges.

The bill provides some protection for electric cooperatives from losing customers to municipal utilities during a four-year period after competition begins.

Finally, the bill leaves open whether the state will use an Independent System Operator or a privately owned transco to manage the transmission grid. Entergy has filed a formal proposal for a transco with the Federal Energy Regulatory Commission (FERC). The Arkansas bill essentially leaves it to FERC to decide whether a transco can be used.

California - After a year of operation California's retail electric market has received mixed reviews. Consumer groups maintain that residential and small business customers have failed to benefit during the first year as utilities have retained their monopoly advantages and prevented competitors from offering lower power prices.

A utility industry group argues that restructuring has given all electricity customers a choice of power suppliers and lower electric rates have attracted new business and economic growth to the state without sacrificing system reliability.

The Utility Reform Network (TURN) is not convinced, and states that because of utilities' monopoly stranglehold, fewer than 1% of the state's residential customers have switched electricity providers, while aggregation has failed to provide a means for small customers to secure lower prices. Moreover, a legislated 10% rate cut for small customers has been eroded to just 2% by mandatory financing charges on rate reduction bonds by the state's three investor-owned utilities.

Californians for Affordable & Reliable Electric Service (CARES), on the other hand, argue that the California Power Exchange has enabled large and small retail customers alike to monitor the price of power and adjust their energy usage to lower their costs and increase efficiency. While acknowledging that residential and small business customers have been slow to switch to new energy service providers, CARES disputes that it indicates flaws in the design or operation of the state's competitive electric market. Rather, deregulation has created a more efficient market with competitive opportunities that will result in greater price savings when the transition period ends in 2002.

The California Independent System Operator (ISO) issued a report March 31, 1999, describing the first year of operation as "trial by fire." Despite weathering volatility and seasonal price spikes in its ancillary services market, the ISO exceeded its projections, processing nearly 700 energy schedules per hour from 27 active scheduling coordinators while delivering electricity without any major power disturbances.

The ISO's computerized control center routed 167 billion kWh of electricity in its first nine months of operation, 3 billion kWh more than its annual projections. As a result the Cal ISO was able to lower its grid management charges in 1999 by half a cent to .77 cents per MWh. Cal ISO transmission charges amounted to about 47 cents for the average customer of an investor-owned utility with a typical monthly household bill $76.31.

Colorado - The engineering firm of Stone & Webster has presented an analysis to a 31-member panel, charged by the Colorado Legislature with reviewing state deregulation options, that indicates a deregulated power market in Colorado would result in sharply higher prices for electricity supplies for end-users. However, if the state's electricity market remains regulated, prices are expected to drop slightly.

The analysis suggests that the significant electricity market share by the state's largest electric utility, Public Service Company of Colorado would thwart competitors.

Also, current low rates in Colorado would limit potential profit opportunities for new competitors working in a deregulated state market.

The legislative panel will review the analysis and is expected to deliver a report to legislators sometime during the summer of 1999.

Connecticut - The Connecticut Department of Public Utility Control (DPUC) has continued its process of initiating electric retail competition with the beginning of its consumer education program. The program is designed to prepare customers for the beginning of customer choice in 2000.

A previous survey of Connecticut customers taken for the DPUC showed a high level of interest in the idea of retail competition in the electric industry, but little knowledge of exactly how it would work. The survey results highlighted the need for an effective customer education program.

The current program calls for a multi-media use of news reports, advertisements, public forums and presentations before civic, community and business groups, internet information, toll-free telephone assistance, the involvement of community-based organizations and the use of foreign language materials.

Delaware - The Delaware Legislature passed and Governor Thomas Carper signed legislation (HB 10) that will open retail competition to industrial customers on October 1, 1999, and extend to all customers by early 2001.

HB 10 calls for retail competition to begin on October 1, 1999, for Conectiv customer with loads of at least 1 MW. Conectiv users with loads of at least 200 kW will be able to shop for electricity supplies starting February 1, 2000, while smaller consumers would gain access to the market on August 1, 2000. The schedule runs six months later for customers of Delaware Electric Cooperative (DEC). The schedule does not apply to municipal utilities that can introduce competition at their own timetable.

Conectiv, which includes the former Delmarva Power and serves most customers in the state, does not have significant stranded costs in Delaware because of its limited nuclear investments and no major independent power contracts. The company will only recover $18-million in restructuring costs and these will only be collected from large commercial and industrial customers.

The bill cuts rates by 7.5% for Conectiv residential customers starting October 1, 1999, and will then freeze rates for four years. Larger customers will only receive the rate freeze, running for three years. In DEC territory, all customers will receive a five-year rate freeze but no rate cuts.

At the end of the four-year transition period, the Public Service Commission could open bidding to replace Conectiv as the default generation supplier for customers that do not select alternative suppliers. If the PSC does not open bidding, it will require the utility to provide generation at market prices.

A number of other consumer benefits are included in the measure as well, including licensing of power suppliers by the PSC, consumer education programs, $800,000 annual funding for low-income customer, $800,000 annually for energy conservation and environmental incentive program and PSC authority to curb market power.

Florida - The Florida Public Service Commission was one of 23 state regulatory commissions that joined together to present the U. S. Congress with various concerns of low-cost states regarding electric restructuring.

The letter stated, in part, "... We want to ensure that low cost states have a national voice in the debate; that Congress understands how low cost rates serve consumers and states in a variety of ways; that rural electricity rates are not disadvantaged; that stranded costs are given thorough consideration; and that economic development advantages are not eroded by restructuring."

The letter requested that low-cost states be allowed to determine whether electric restructuring is appropriate on a state-by-state basis without federal mandate.

The 23 state commission signing the letter included: Alabama, Florida, Georgia, Idaho, Indiana, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Montana, North Carolina, North Dakota, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Utah, Virginia, Washington, West Virginia and Wisconsin. In these 23 states, the average retail price for electricity is 5.52 cent per kilowatt-hour, more than one cent below the national average.

Georgia - There has been no significant electric industry restructuring activity in Georgia during 1999.

The Georgia Public Service Commission was one of the signatories of a letter to the U.S. Congress outlining the concerns of low-cost states regarding federally mandated electric industry restructuring. See the entry for Florida for more details about the letter.

Hawaii - Due to its geographical location, the Hawaii Commission was not contacted.

Idaho - In May 1998, Washington Water Power launched a two-year customer choice pilot program in Hayden and Hayden Lake, Idaho and Deer Park, Washington.

The More Options for Power Service II program offers five pricing options: a Monthly Market Rate, an Annual Market Rate, a fixed rate based on Bonneville Power Administration's preference rate, a renewable resource rate and WWP's traditional rate.

Since the initiation of this program, there has been no other restructuring activity in Idaho.

Illinois - There has been significant restructuring activity in Illinois over the past 12 months as the implementation of customer choice commences.

The Illinois Commerce Commission (ICC) ruled that a lottery to determine which commercial customers will be eligible to participate in customer choice beginning October 1, 1999, must select candidates from among customers who have previously registered with the local utility rather than from the at-large pool of commercial users.

Electric utilities were joined by the ICC staff in recommending to the commission that lottery candidates be drawn from the entire pool of commercial customers not otherwise qualified under the 4 MW and 95 MW categories. Utilities characterize a pre-lottery registration as a "first-come, first-served" approach that violates the Illinois restructuring law because it is discriminatory, allowing the same interested, well-informed customers to sign up each time.

Arguing on behalf of the registration process were Black-hawk Energy Services, Enron and NEV Midwest, New Energy Ventures' operational subsidiary serving Illinois. They asked the ICC to adopt a selection process similar to other lotteries where there is an enrollment process, such as the Illinois State Lottery. The three companies objected to the utilities' proposal on the basis that it would result in the selection of eligible customers who are uninterested in or unsuited for delivery services.

In addition, power marketers see the utilities' proposal as anti-competitive. If adopted, it would result in direct access participation far short of the one-third of utilities' non-residential load envisioned by the legislation.

In its February 26 order, the ICC stated it was "reasonable to conclude that initiating the selection process with a registration requirement is likely to lead to greater competition than if no action were required on the part of the customer."

The ICC also ruled in favor of the power marketers on the disclosure of utility rate classification data. All parties agreed that utilities would release customer names and addresses unless a "negative" check-off was received – i.e. the customer specifically forbade the utility from releasing the information.

Indiana - For the third straight year, restructuring legislation has failed in Indiana.

Senate Bill 648, which originally would have ushered in competition starting January 1, 2002, was amended to allow for an 18-month pilot program but failed to gain enough support to pass out of the Senate Commerce and Consumer Affairs Committee.

Iowa - Iowa legislators decided to postpone passage of any electric industry restructuring bill during the 1999 session, deferring consideration until early 2000 in order to educate the public and the Iowa General Assembly.

Kansas - The Kansas Legislature continues a go-slow approach to restructuring of the electric utility industry. No new legislative measures have been considered since the 1997 legislative session.

The Kansas Corporation Commission has focused its attention on the adequacy of generation capacity after the shortages experienced during the summer of 1998.

Kentucky - The Kentucky Public Service Commission joined 22 other states as a signatory to a letter to the U.S. Congress against a federal mandate on electric industry restructuring. See the Florida entry for more details.

Louisiana - The Louisiana Public Service Commission (PSC) has ordered its staff to move ahead with studies and hearings on restructuring issues and draw up a complete restructuring plan for the state by January 1, 2001.

The PSC refused to take any vote on whether restructuring was in the public interest; saying it would make a decision once it reviews the final plan.

It also did not propose a date for the actual start of retail competition but members said that once a decision is made they might support a pilot program starting in early 2001 and implementation of full choice later that year.

The commission members said they believe Louisiana should be ready with a deregulation plan because of moves by other states in the region towards decontrol. They want Louisiana to stay in line with neighboring states and not begin choice ahead of them. Both Texas and Arkansas legislatures have passed bills that will begin customer choice in 2002.

Unlike the other states, the Louisiana PSC has the power to order deregulation without new legislation. Therefore once the commission makes a decision, implementation can proceed quickly.

Maine - In April 1999, the Public Utilities Commission (PUC) approved the first license to a competitive electricity provider in Maine as part of the restructuring of the state's electricity industry. The PUC license authorizes the Maine Health and Higher Education Facilities Authority (MHHEFA) to market electric generation service to Maine customers. MHHEFA is the first entity, of more than a dozen registered with the PUC, to apply for a license.

MHHEFA will operate "Maine Power Options Program" providing electricity aggregation services for nonprofit health care and higher education institution throughout Maine.

In 1997, the Maine Legislature deregulated electric generation and allowed for retail competition beginning on March 1, 2000. Maine's electricity consumers will then be able to choose a generation provider from a competitive market. The Legislature required that the PUC license all marketers, brokers, aggregators and other entities selling electricity to the public and set several conditions for licensed competitive electricity providers.

Maryland - Maryland legislators passed electric restructuring and tax reforms bills and Governor Parris Glendening signed the bills on April 8, 1999.

The restructuring legislation (SB 300 and HB 703) will phase-in competition between July 2000 and July 2002. The measures open competition for residential customers in three stages, while commercial, industrial and institutional users will gain access to the market in 2001.

The bill provides for residential rate cut of 3% to 7.5%, with a four-year rate cap.

The Public Service Commission on a case-by-case basis will determine stranded costs for each utility. PEPCO estimates stranded costs of $600-million in Maryland but expects that do be reduced once its generation is auctioned off. Baltimore Gas & Electric estimates $1.1-billion in stranded costs. Allegheny Energy estimates $241-million in stranded costs for its Maryland territory and Conectiv estimates $69-million. The utilities could offer a settlement on their stranded costs before their cases come to hearing.

Other provisions of the legislation include utility disclosure of fuel mix in order to monitor environmental emissions and continued Universal Service for low-income customers.

The legislature also passed a tax reform bill which reduces utility property taxes to 40% of assessed value, and establishes a "share the pain" system that splits the shortfall between counties, ratepayers and the state. Under the new system, utilities will also become subject tot state income tax, like other businesses. The franchise tax will be removed from generation and replaced by a 0.065 cents/kWh tax. This tax will apply to all generation, whether it is from utilities or other suppliers.

Massachusetts - During the fall of 1998, The Campaign for Electric Rates succeeded in placing a question on the November ballot to repeal the state's restructuring law. On November 3, 1998 Massachusetts's voters approved retaining the retail choice law.

Also in the fall of 1998, Unitil/Fitchburg Gas & Electric was the first Massachusetts utility to strike a deal for standard offer power through a competitive solicitation. Constellation Power Source, a subsidiary of Baltimore Gas & Electric, signed a contract to sell FG&E power beginning at

3.5 cents/kWh. Other utilities have been unable to attract credible bids for their standard offer because it is priced below market price.

Massachusetts utilities are required to supply standard offer power to any customer who declines to enter the competitive marketplace. Regulators pushed for low standard offer prices so that customers would experience immediate savings under industry restructuring.

Michigan - Although the Michigan Public Service Commission (PSC) has set September 20, 1999, as the date final bids are due on the first block of capacity for open access, customers contemplating choice are facing two looming developments before moving forward: the pending Michigan Supreme Court decision on whether the PSC has statutory authority to order retail wheeling in Michigan, and new electric industry restructuring legislation introduced in June 1999.

The new legislation, spearheaded by the Michigan Chamber of Commerce, contains provisions not included in the PSC's regulation-based direct-access rules.

Senate Bills 642, 643 and 644 and House Bills 4789, 4790 and 4791 have been introduced to provide a focal point for negotiations over the summer in an effort to build consensus by September 1999.

Among the key provisions of the proposed legislation is one that prohibits generation rate deregulation until Michigan lawmakers decide that competition exists. Based on the model for the deregulation of the workers compensation insurance market, it is subject to limited exceptions. Under this provision, the PSC beginning in late 2002 is directed to compile annual reports on the state of competition in Michigan.

The bills call for a series of market power mitigation efforts to encourage competition. A legislative finding that competition exists allows the PSC to deregulate generation rates on a customer class basis, although rate cannot exceed utility tariffs in place as of December 31, 1998.

A legislative finding that competition does not exist in a given customer class allows the commission to regulate the generation rates of large utilities, subject to the rate cap. The PSC can reduce rates, however.

Further, Consumers Energy and Detroit Ed. Are required to upgrade their transmission import capacity or suffer penalties, and they are directed to join a regional transmission operator that will assure non-discriminatory access to the transmission systems and encourage system upgrades on a regional basis. The proposal provides penalties for failure to join such a RTO or similar organization within a specified period.

In addition, utilities are required to functionally, and in some cases structurally, separate their business units in order to assure that their regulated rates do not subsidize their competitive businesses.

Utilities are critical of the bills. The Consumers Energy said the bills target the two largest Michigan utilities, while granting substantial exemptions to the rest. It would effectively force the breakup of Consumers Energy and Detroit Edison, while leaving other utilities and other large integrated energy supply companies intact.

Consumers Energy also called the plan "technically naïve" in that Consumers and Detroit Ed. Must continue to be responsible for electric reliability in Michigan while being "completely unable to ensure that reliability because of their break up – an impossible situation."

It is also unrealistic, Consumers contend. It contains impossible mandates for new transmission facilities and fails to recognize the public's strong opposition to new transmission lines in their back yards.

Assuming ratification by the Michigan Supreme Court of the Michigan Public Service Commission's authority to order electric industry restructuring, direct access is set to commence early in the fourth quarter 1999. September 20, 1999, is when final bids are due on the first block of capacity for open access. Bids for the next three blocks are due November 19, 1999, January 20, 2000, and March 20, 2000.

Consumers Energy and Detroit Edison will be required to offer standby service on a "best-efforts" basis. According the PSC, standby service must be available to open access customers who request it, but the two utilities are not required to build or purchase new capacity, nor must they interrupt firm customers to offer it. Standby service is to be available as long as the utilities are unable to make firm transmission service available to the open access customer and his supplier. The PSC ordered the utilities to charge their top incremental cost plus 1-cent/kWh for standby service.

Minnesota - During the past twelve months there has been little electric industry restructuring activity in Minnesota. The Minnesota Public Utilities Commission (PUC) joined with 22 other state commissions in sending a letter to the U.S. Congress expressing the concerns of low-cost power states on federally mandated electric industry restructuring. See the Florida entry for more details on the letter.

In January 1999, Northern States Power, anticipating the transfer of its transmission and generating assets to separate, independent companies, proposed a methodology for separating electric service costs into their respective business functions to the PUC. Due to the complexity of the filing, Northern States asked the PUC to vary its usual filing procedure and schedule an informal technical conference to review the filing. No further action has been taken on this filing.

Mississippi - During the past twelve months there has been little electric industry restructuring activity in Mississippi. Some electric industry restructuring measures were considered by the legislature but all died in committee.

The Mississippi Public Service Commission (PSC) joined with 22 other state commissions in sending a letter to the U.S. Congress expressing the concerns of low-cost power states on federally mandated electric industry restructuring. See the Florida entry for more details on the letter.

Missouri - A final report by the Missouri Retail Competition Task Force in 1998 called for the cautious approach to deregulation but made no other recommendation. There has been no significant restructuring activity since then.

The Missouri Public Service Commission joined with 22 other state commissions in sending a letter to the U.S. Congress expressing the concerns of low-cost power states on federally mandated electric industry restructuring. See the Florida entry for more details on the letter.

Montana - Customer choice opened to nearly 250 industrial power users on July 1, 1998 although few were expected to quickly switch to alternative suppliers. A large number of companies were hesitant to make commitments to alternative suppliers until transition charges and universal system benefit charges for social and conservation programs were determined.

The Montana Public Service Commission joined with 22 other state commissions in sending a letter to the U.S. Congress expressing the concerns of low-cost power states on federally mandated electric industry restructuring. See the Florida entry for more details on the letter.

Nebraska - This unusual state with a unicameral legislature and 100% public power has begun a three-year legislative study of the state's electric power industry. The goal is to examine moves towards competition in the industry nationwide and develop alternatives to enhance the ability of Nebraska's public power industry to thrive in a competitive environment. Phase I of the study, completed in 1997, examined the structure of the power industry in the state and issues facing the state's electric utilities. Phase II is an in-depth analysis of issues related to competition and of possible policy changes to strengthen public power's position in the future. This phase will be completed by the end of 1999.

Nevada - As an outgrowth of a November 1998 order approving Nevada Power Company's request to unbundle certain service and declare billing, customer services and metering as "potentially competitive", the Public Utilities Commission (PUC) of Nevada ordered the formation of "working groups" to examine various aspects of electric industry deregulation.

Topics examined by the working groups include; the determination when, and if, alternative electricity suppliers should enter the market, protocol to use for competition in metering services, appropriate stranded cost recovery and how best to forecast future electric capacity.

In April 1999, the PUC approved the formation of an independent system administrator to regulate transmission within the state following implementation of a competitive power market, although no start date has yet been set.

The Nevada Assembly approved an amendment to the state's electricity restructuring law, A.B. 366, approved in 1998. The amendment sets the beginning of competition for

March 1, 2000 and imposes a three-year rate freeze on Nevada Power Company and Sierra Pacific Power Company, the state's incumbent utilities.

The measure also delays the auction of small default customers, those end-users not selecting an alternative provider once competition begins, until July 2001. A.B. 366 had originally set the auction at the start of competition.

New Hampshire - In a possible breakthrough in a three-year stalemate over restructuring, the state reached a preliminary agreement with Public Service New Hampshire on a plan to begin retail choice for its 420,000 customers starting in early 2000.

The plan announced by Governor Jeanne Shaheen June 14, 1999, would give PSNH retail customers an 18% rate cut when retail choice begins and another 15% to 20% cut in 2007 when PSNH would have to have recovered all stranded costs.

PSNH, a Northeast Utilities unit, would be found to have a total of $1.9-billion in stranded costs. It would be allowed to securitize $725-million of that. The company has agreed to write off $225-million on an after tax basis, which would represent a $367-million savings rate.

It would also auction off its 1,188 MW of fossil and hydro generation along with a contract to buy power from the 409-MW share of the Seabrook nuclear plant, owned by NU unit North American Energy. Those proceeds would be applied to paying down stranded costs.

PSNH also assumes some financial risk: any stranded costs remaining unrecovered in 2007 must be absorbed. Under the new plan, it would recover about 85% of stranded costs.

PSNH is to provide transition energy service for three years starting at 3.7 cents/kWh in 2000 and increasing to 3.9 cents/kWh in 2002. It would procure power for the service through an auction.

New Hampshire passed one of the first deregulation laws in the country in 1996 and in February 1997, the Public Utilities Commission issued a restructuring plan for PSNH which would have cut rates 18%, allowed only 60% stranded cost recovery, and barred securitization.

PSNH, arguing that the plan would push it into bankruptcy, filed suit in U.S. District Court and won an injunction preventing the PUC from taking further action. The case has not come to trial and the state has held a series of negotiations with PSNH to avoid a legal showdown. Under the latest proposal, all legal proceedings connected to the case would be stayed and the PSNH complaint would be dismissed when the plan is implemented and retail competition begins.

The two sides plan to convert their memorandum of understanding into a final detailed plan and file it with the PUC on August 1, 1999.

They are also asking the state legislature to take action granting the PUC authority to approve securitization of PSNH's stranded costs. The legislature passed similar bills in May 1999, but tied stranded cost recovery to strict rate reductions, which are tougher than those in the new agreement did.

New Jersey - The New Jersey Legislature has passed a restructuring measure (A-16, S-7) that opens retail competition for all customers on August 1, 1999, and cuts rates by 10% over three years, including an immediate 5% reduction.

The Board of Public Utilities will set shopping credits for each utility rate class.

The new law gives utilities the "opportunity" to recover 100% of their stranded costs, but the final allowances will be determined by the BPU in public proceedings. Public Service Electric & Gas requested $5.4-billion, while GPU Energy Sought $1.8-billion and Conectiv $1.3-billion. Utilities may "securitize" up to 75% of allowed stranded costs by issuing bonds.

Another provision of the legislation requires suppliers – including utilities and competitors – to disclose their sources of power and emissions. They must also include certain percentages of renewables in their portfolios: 2.5% of the kWh that they sell in New Jersey must come from hydro or waste; and starting in 2001 0.5% must come from photovoltaics, wind, fuel cells, biomass or tidal power. That second category rises to 1% in 2006 and increases 0.5% each year until 2012, when 4% must come from those categories of renewables.

The legislation also requires utilities to maintain their 1997 budgets for demand-side management, which ran $230 million. Half of that, or $115 million, must be directed to new programs, and 25% of that half must be fund renewables. In the eighth year, new programs must receive $140 million.

When competition begins, municipalities may "aggregate" residential users into buying groups. A municipality may set up a buying group by ordinance, but the marketer that it chooses to serve the group must obtain written approval from individual ratepayers before including them.

Since the restructuring measure was passed the New Jersey Board of Public Utilities has approved restructuring plans for Public Service Electric & Gas (PSE&G) and GPU

Energy's Jersey Central Power & Light (GPU). A restructuring settlement for Conectiv is currently pending.

Provisions in the restructuring plan for The Public Service Electric & Gas include:

- Recovery of up to $2.94 billion in generation-related stranded costs, and PSE&G may securitize $2.4 billion of that by issuing bonds. PSE&G will have "an opportunity to recover" $540 million, but that unsecuritized portion will be subject to a true up, based on the market
- Reductions in rates by 13.9% over four years: 5% in August 1999, rising to 7% in January 2000, to 9% in August 2001, and finally increasing to an average 13.9% in August 2002. Over four years the rate cuts will amount to more than $1.5 billion
- Shopping credits, which average: 1999, 4.95 cents/kWh; 2000, 5.03 cents/kWh; 2001, 5.06 cents/kWh; 2002, 5.1 cents/kWh; and 2003, 5.1 cents/kWh. By class, they run: residential, 5.71 cents/kWh in 1999, rising to 5.86 cents/kWh in 2000-2003; commercial, 4.54-5.3 cents/kWh in 1999 (depending on the subclass), rising in steps to

4.54-5.3 cents/kWh in 2003; industrial, 4.12-4.3 cents/kWh in 1999, rising in steps to 4.44cents in 2003.

- PSE&G will be allowed to transfer its generation assets to a separate entity that would be owned by the holding company. The new unit would sell power into the wholesale market and provide the utility with "basic generation service" (for customers that do not shop) for two years. After that, basic generation service will be put out to bud, and any profit from this bidding must be credited 100% to ratepayers. Further, if PSE&G sells its generation to an outside party within five years, any profits must be split 50-50% between shareholders and ratepayers.

Provisions in the restructuring plan for GPU Energy include:

- Shopping credits would average 5.13 cent/kWh effective August 1, 1999, when deregulation starts then rise to 5.27 cent in 2000, 5.31 cent in 2001, 5.36 in 2002 and 5.4 cents in 2003. Shopping credits for residential users start at 5.65 cents and rise to 5.85 cents in the second year before leveling off while industrial and commercial levels remained generally unchanged.
- Rate reductions totaling11% by 2002. Rates would drop 5% on August 1, 1999, 1% in 2000, 2% in 2001 and 3% in 2003.
- Commercial and industrial users who switch from an outside supplier back to GPU's basic generation offer may not switch again for a year.

Provisions in the proposed Conectiv restructuring plan include:

- Recovery of $800 million in stranded costs related to above-market independent power contracts and it could securitize the full amount by selling bonds. The $800 million would be collected over the lives of the independent power contracts. Conectiv has agreed to forego recovery of about $9 million in stranded costs associated with its combustion turbines and the Deepwater Generating Station, which may not be sold.
- Shopping credits under the accord will average 5.09 cents/kWh in 1999, 5.14 cents/kWh in 2000, 5.17 cents/kWh in 2001, 5.23 cents/kWh in 2002 and 5.28 cents/kWh in 2003.
- Rate reductions of 5% and another 5% within three years. Conectiv would continue those lower rates through July 31, 2003.

New Mexico - The New Mexico Legislature unanimously approved SB 428, the Electric Utility Industry Restructuring Act of 1999, and Governor Gary Johnson signed the measure on April 8, 1999.

Under SB 428, starting January 1, 2001, residential and small business customers will have electricity supplier choice options. Competition will expand to all other customers on January 1, 2002. Over a five-year transition period, utilities may recover up to 100% of stranded costs, but the Public Regulations Commission (PRC) must approve the level of recovery.

The largest utility in the state, Public Service New Mexico, estimates its stranded costs at between $300 million and $600 million. It is unlikely PNM will be able to recover much more than 50% of its stranded costs because the measure says rates cannot be increased to do so.

The bill contains strong provisions to guard against incumbent utilities using their market power to favor or subsidize their own generation resources. While utilities are not required to divest any part of their business, they would be required to separate those businesses from their regulated activities in transmission and distribution.

All utilities must file a transition plan and have that plan approved by the PRC. The filing must be made no later than March 1, 2000. The PRC is required to either approve the plan or undertake changes no later than December 1, 2000.

The transition plan must include: proposals to implement customer choice and open access; methods for effectively separating the utility's regulated and non-regulated business activities; unbundled rates for distribution, transmission and related services; a rate setting procedure and proposed tariffs for the standard offer; and a proposed wires charge for the recovery of stranded costs and transition costs.

The bill also includes a system benefit charge to be added to all customers' bills to fund low-income energy assistance and renewable energy projects in New Mexico.

Utilities are also required to offer a standard package of electric service for customers opting not to shop for a new supplier.

New York - In 1998, the Federal Energy Regulatory Commission approved the New York Power Pool's proposal to establish an independent system operator. In its order, FERC told the transmission-owning utilities, negotiating with other parties, to revise their governance procedures to reduce their own voting power.

In February 1999, the Federal Energy Regulatory Commission rejected the New York Independent System Operator's governance structure, finding its revised plan still weighs too heavily in favor of transmission-owning utility members. FERC told the ISO it has 60 days to file a new plan that meets its approval, or the commission will impose a governance structure that ensures the necessary. There has been no recent activity in this case.

In other electric industry restructuring activity, the Board of Trustees of the Long Island Power Authority (LIPA) has approved a retail competition plan that will open competition this summer and phase-in the change to all customers by 2003.

LIPA took over electric service on Long Island last year when it acquired the transmission and distribution assets of Long Island Lighting (LILCO). It serves about 1 million customers, buying most power from KeySpan, the entity that acquired LILCO's 4,000 MW in fossil plants. LIPA cut LILCO's 15-cent/kWh rates by 20% at that time.

Under the competition plan, enrollment will run from March 1 through May 31 for a 400-MW block, with deliveries starting in August 1999. The capacity will be allocated as follows: 180 MW for residential customers, 80 MW for small commercial users, 100 MW for large commercial customers and 40 MW for government accounts. That will cover about 90,000 residential and 10,000 commercial customers. In May 2000, LIPA will open another 400 MW and in 2001, it will begin phasing-in the change to all customers, opening its entire market by January 2003.

LIPA has estimated that retail choice will let customers cut their bills another 2%-5%, beyond the earlier rate reduction.

North Carolina - North Carolina legislators are unlikely to receive a final report from the special electric industry-restructuring panel until early 2000; a year later than initially planned. A spokesman for the Study Commission on the Future of Electric Service in North Carolina said the panel's progress was slow for several reasons. First, the commission is only permitted to meet only when the state's General Assembly is not in session. This has limited the number of times the commission has been able to work on the report.

Second, it took longer than expected for consultant, Research Triangle Institute (RTI), to complete its studies on stranded costs and other complex restructuring issues.

Finally, the commission still must solicit input from stakeholders on the question of restructuring North Carolina's electric industry before a final report can be prepared.

The panel's delay in sending a final report to the General Assembly is expected to push back serious legislative action on restructuring until 2000.

In other restructuring activities, a group representing 51 North Carolina municipal utilities said it would support a compromise approach to dealing with stranded costs in the state. Members of the municipal groups face several billion dollars in mostly nuclear-related stranded costs, much more than other utilities in the state.

Under the compromise plan, rates for all incumbent suppliers – IOUs, municipals and electric cooperatives – would be frozen for five years, with municipal rates remaining relatively high and IOU and co-op rates relatively low. All suppliers would earmark a portion of their above-market revenues to help pay the state's stranded costs: the contributions would be pooled and all stranded costs would be eliminated over the five-year rate-freeze period. Retail wheeling would begin when the rate freeze ends.

The municipal groups had originally proposed a uniform "wires" charge that over five years would eliminate all stranded costs but this plan was strongly opposed by the investor-owned utilities and others.

North Dakota - February 1997, the North Dakota Public Service Commission adopted the NARUC principals, as a guide for possible restructuring of the electric industry. The NARUC principles emphasize that changes in the industry should occur only when they meet two goals – improve economic efficiency and serve the broader public interest.

Since 1997, neither the North Dakota Public Service Commission nor the state legislature had taken any action on electric industry restructuring.

Ohio - Senate Bill 3 was passed by the Ohio House of Representative on June 17, 1999, and was approved by the Senate in a concurrence vote on June 22, 1999. Governor Robert Taft signed the measure that will deregulate the state's $11 billion electricity industry starting January 1, 2001.

S.B. 3 would guarantee a 5% rate cut for residential customers for 2.5 years, or halfway through a transition period ending December 31, 2006. For many ratepayers, the savings would amount to between $2 and $3 a month.

Prior to the final vote, the Senate approved an amendment that deleted a controversial provision to "auction" customers who did not switch electric suppliers by the end of the transition period. Consumer groups generally favored the auction while the state's investor-owned utilities strongly opposed it.

The critical issue of determining stranded costs for utilities would be left to the Ohio Public Utilities Commission; a provision disliked by both utilities and consumer advocates. Utilities want the right to recover as much as $13 billion to $14 billion in stranded costs, mostly for nuclear investments. Consumer groups contend any stranded cost recovery is unjustified, though they probably would accept about $5 billion.

Oklahoma - In 1998, Oklahoma lawmakers passed Senate Bill 888 and Governor Frank Keating signed the measure, smoothing the way towards electric deregulation in the state by 2002.

On the deregulation front, the bill makes no final determinations on how such major issues as stranded costs or tax implications are resolved. It does speed up and more clearly defines the study process that will lead to those solutions.

The bill also clarifies the status of supplier switching until competition arrives. Cooperatives, investor-owned utilities and municipal utilities will be unable to take customers from each other unless both utilities agreed to the switch. It also sets a moratorium on municipal utilities condemning and taking over the lines and customers of other utilities until July 2002 or when retail competition arrives, whichever is first.

There has been no further significant restructuring activity in Oklahoma since the passage of SB 888.

Oregon - There has been both legislative and regulatory activities on electric industry restructuring over the past twelve months.

SB 1149 would allow open access to industrial customers of investor-owned utilities in 2001 and allow residential and small commercial customers to choose from a range of options, including market-based rates and green rates. It also would provide a mechanism for funding conservation and renewable resources in the deregulated environment.

The measure has passed the Oregon House of Commerce Committee and is expected to go to the full House by the week of June 21, 1999. It has already passed the Oregon Senate.

Other legislative measures currently being considered by the Oregon legislature are HB 3359 and HB 2667. HB 3359 is sponsored by the Fair Clean Energy Coalition, a coalition of public interest and environmental groups. The bill would allow large customers to shop for suppliers and would give smaller customers a limited portfolio of choices, including green power and market-based rates. It intends to protect rivers near hydroelectric dams, provide funding for investments in renewable energy and give consumers information about their energy sources.

HB 2667 establishes a placeholder for a future restructuring legislation.

The Oregon Public Utility Commission rejected much of Portland General Electric's (PGE) restructuring plan. The OPUC instead called for direct access for industrial and some commercial customers, a portfolio approach for other customers and said PGE may not sell its hydroelectric resources.

Under the portfolio option, residential customers do not have direct access. Instead PGE will take title to power from energy service providers and deliver it to customers. The portfolio approach generally includes market-based power, green power and other options.

The OPUC rejected direct access for residential customers because it would be too risky, given that there is no "viable" energy market for residential customers and they would have fewer choices and possibly higher rates.

The order also stated that PGE's customers would be best served if the company retain its hydroelectric resources. This ensures that customers receive the maximum value of those resources.

Pennsylvania - Electric choice became a reality for Pennsylvania consumers on January 1, 1999. Nearly 1 million Pennsylvanians signed up for the electric choice pilot program that began in November 1997, for approximately 230,000 available slots. Noting the success of the pilot program enrollment, Public Utility Commissioner Chairman, John M. Quain cited additional indicators of success of the Electric Choice Program:

- Guaranteed Rate Reductions – As a result of the utility restructuring mandated by the Electricity Competition Act, electric customers statewide will save a minimum of $458 million in rate reductions during 1999.
- Widespread Participation – Nearly 2 million electric customers enrolled in the program from July 1998 through December 1998. A survey completed in December found that 22 percent of all customers said they had actively shopped for an electric supplier. This represents over a million customers.
- Strong Community Involvement – More than 1,000 community-based organization participated in consumer education efforts, including many groups that served hard-to-reach constituencies.

Quain stressed that there is no deadline for selecting an electric generation supplier and encouraged customers to compare the rates offered by competitive suppliers.

Rhode Island - Retail competition began on January 1, 1998 in Rhode Island, since that time there has been no significant legislative or regulatory activity related to retail competition.

South Carolina - Representative Harry Cato, chairman of the House Labor, Commerce and Industry Committee, introduced an electric industry deregulation bill (HB 3902) that calls for a six-year transition to full retail competition. The bill requires participation by all the state's electricity suppliers, including investor-owned South Carolina Electric & Gas,

Duke Power and Carolina Power & Light plus state-owned Santee Cooper, municipal utilities and electric cooperatives.

One-fifth of each utility's load would be opened to competition in the fourth year of the transition, followed by another 20% in the fifth year and still another 20% in the sixth year. At the end of the sixth year, all customers could choose their supplier.

During the early staged of the transition the state's Public Service Commission would oversee the development of an independent system operator that would manage the transmission system.

The bills also calls for the recovery of stranded cost over no more than ten years through a "wires" charge, exit fee and other means to be determined later by legislators. The bill forbids the incorporation of the cost of consumer, social or environmental programs into basic utility rates.

The bill was sent to committee and there has been no further action on it.

South Dakota - There has been no electric industry restructuring activity in South Dakota.

Tennessee - In a major split inside the Tennessee Valley Authority (TVA) region, large municipal utilities in Knoxville and Memphis oppose key portions of a restructuring plan being prepared by TVA for review by the Clinton Administration.

The disputes involve federal jurisdiction over TVA rates, contract rights for TVA distributors and opening the TVA area to outside power sellers. In all cases the two municipals have taken positions more in line with those of investor-owned utilities in the region and have broken ranks with other TVA distributors – represented by Tennessee Valley Power Association (TVPA) – who have been more ready to compromise with TVA on several key issues.

TVA is hoping to act together with TVPA to propose a restructuring plan for its region, which will be used to help draw up a final Administration restructuring bill.

The Knoxville Utilities Board (KUB) and Memphis Light Gas & Water (MLG&W) Division are calling for full Federal Energy Regulatory Commission jurisdiction over TVA wholesale rates which would insure TVA received equal regulatory treatment with other public utilities.

TVA, which is not completely unregulated, only wants to allow limited FERC jurisdiction over its transmission and stranded cost recovery but not over wholesale rates. The TVPA wants some ability to appeal TVA rates in federal courts but not full FERC oversight.

At the same time KUB and MLG&W say that TVA distributors should be allowed to give one-year notice on their current TVA contracts after restructuring begins so that they would have more bargaining power in contract negotiations with TVA.

The two municipals also oppose any regulation of distributors in the region saying it would create an immediate conflict of interest. The TVPA, hoping to avoid state regulation, wants to maintain some TVA oversight over their operations.

KUB and MLG&W also say Congress should quickly open the TVA area to outside power sellers by a date certain while TVA wants to link the opening to Congressional action to mandate nationwide retail choice.

The two utilities are among TVA's largest wholesale customers and they have been discussing retail competition issues informally for the last two years with other large municipals served by TVA in Nashville, Chattanooga and Huntsville, Ala. But the new dispute over restructuring recommendations is the first actual break between any of the "Big-Five" and the rest of the TVPA which is dominated by smaller municipals and cooperatives who have tended to be less independent of TVA.

Any plan based on the TVA's proposals is likely to be strongly attacked in Congress by investor-owned utilities and groups from outside the region.

Texas - On June 18, 1999, Governor George W. Bush signed into law a bill that will restructures the electric utility industry in Texas, allowing electricity customers a choice.

The electric industry restructuring bill, Senate Bill 7, was authored by Senator David Sibley and approved by the Senate on March 17, 1999. The bill was amended in the House under the sponsorship of Representative Steve Wolens and approved on May 21, 1999. The Senate voted on May 27 to concur with the House version.

Key provisions of the bill include:

- Choice of electric providers will begin on January 1, 2002 for customer of most investor-owned utilities. The affiliated retail provider (REP) of the utility that serves the customer on December 31, 2001 will continue to serve the customer unless the customer chooses another REP. Municipally owned utilities and cooperative may elect to offer customer choice after January 1, 2002. Each utility will launch a pilot project beginning June 1, 2001, to offer choice to 5 percent of the utility's combined load.
- The law calls for a statewide reduction of 50 percent in the generation of nitrogen oxides (NOx) and a 25 percent reduction in sulfur dioxides (SO2) from "grandfathered" power plants. Costs associated with the air quality improvements are recoverable. The law calls for tripling the state's renewable power generation by the year 2009.

- Customers' interests and fair competition are also protected. Customers will receive information to permit comparisons between service and prices. They will also be protected from unfair practices, such as slamming, and may elect to be put on a list to prevent unwanted telephone solicitation from REPs.
- REPs must be certified by the Public Utilities Commission of Texas (PUC) and electric generators and other parties must register with the UPC. The PUC may suspend registration and certifications or impose administrative penalties for violation of its rules. One such rule is that during the first three years of competition, any REP that serves aggregated load in excess of 300 MWs must serve residential customers for at least 5 percent of the company's total load or pay a fee into the system benefit fund. A system benefit fund is established to fund customers' education, provide low-income assistance program and replace any state and local school finding reductions that may result from restructuring the electric industry.
- The bill freezes rates of most investor-owned utilities until competition begins, than provides a 6 percent reduction for residential and small commercial customers. Rates will be capped at this "price to beat" for five years. Affiliates of the investor-owned utilities may compete for large business customers immediately and for residential and small commercial customers after three years or when 40 percent of the designated customer classes have chosen new providers. The "price to beat" applies to the utility's service area.
- Each utility that has stranded costs may redirect depreciation expenses relating to transmission and distribution assets to its generation plant assets from 1998 through 2001. The utility may also apply any earnings during the rate freeze period of 1999 through 2001 that are above the utility's most recently approved cost of capital to generation depreciation.
- Electric utilities are allowed to recover all net, verifiable, nonmitigated stranded costs incurred in purchasing power and providing electric generation service. Securitization allowed as a mechanism for recovery, permits utilities to refinance investments and costs incurred under a regulated environment. For recovery, a utility may securitize 100 percent of its regulatory assets and initially up to 75 percent of its stranded costs as estimated using the Economic Cost Over Market (ECOM) model of the PUC. Remaining stranded costs can be securitized after a true-up proceeding in 2004. In the true-up proceeding, the actual level of stranded costs will be determined using market-based methods, with the possible use of the ECOM model for certain nuclear generation assets.
- Capacity owned and controlled by a power generation company is limited to 20 percent of the installed generation capacity in a power region. Most of Texas is in the Electric Reliability Council of Texas, ERCOT, power region. The capacity limitation for

certain utilities is reduced if the company commits to meeting certain air quality standards for "grandfathered" plants in non-attainment areas. Most utilities will auction entitlements to at least 15 percent of the generation capacity for five years or until 40 percent of the residential and small commercial consumption of electricity in the utility's service area is provided by a nonaffiliated REP.

Utah - On November 18, 1998, the Utah Public Service Commission issued a final report on electric industry deregulation to the to the Utah State Legislature. The report concluded that consideration of a comprehensive electric restructuring plan during the 1999 General Assembly was premature. The report recommended that consideration of a restructuring plan should be deferred until conditions were appropriate. The report also recommended further study of the issue and the monitoring of restructuring activities on the federal level and in other states, stating these actions would position Utah to implement restructuring when it was in the best interest of the state.

Since the report was issued there has been no significant restructuring activities in Utah.

Vermont - In October 1998, The Vermont Public Service Board opened and investigation into the reform of Vermont's electric power supply. The state's utilities and other interested parties filed position papers and a technical conference was held in February 1999.

The investigation is still open, no findings or final order has been issued at this time.

Virginia - March 30, 1999, Governor James Gilmore signed the Electric Utility Restructuring Act of 1999, detailing the planned transition to a mostly deregulated retail power market. Utilities, independent power producers and large industrial customers backed the law (S.B 1269). It requires retail utilities to join or set up regional transmission entities by January 2001; a transition to retail competition starting by January 2002; and full retail wheeling by January 2004. The law allows the State Corporation Commission (SCC) to delay implementation of universal customer choice for up to a year if the SCC finds reliability, safety, and/or market power issues unresolved.

The law caps retail rates until July 1, 2007, but customers who switch suppliers before then must pay a "wires" charge to allow the utility to recover stranded costs. The law bars the SCC from requiring utilities to divest generation or wires assets, but utilities must separate generation, transmission and distribution operations by January 2002.

Finally, the law requires licensing of retail electricity suppliers; permits municipalities to aggregate small customers into buying groups; and directs a special legislative task force to monitor whether utilities may be over-recovering or under-recovering stranded costs.

Washington - On July 1, 1998, Washington Water Power launched a two-year customer choice pilot with 7,500 residential, commercial and agricultural potential participants in Hayden and Hayden

Lake, Idaho and in Deer Park, Washington. The More Options for Power Service II (MOPS II) program offers five pricing options to participants.

The Washington legislature passed a bill calling for the utilities to submit studies on unbundling their costs. The bill was partially vetoed by the Governor on April 2, 1998.

The final bill required each investor-owned electric utility to file unbundling studies by September 30, 1998, and consumer-owned utilities to submit studies by October 1, 1998 to the Washington Utilities and Transportation Commission. In December 1998, the WUTC and the state auditor were to submitted joint report on study results to the legislature. There is no further information on the status of the joint report.

There has been no significant electric industry restructuring activity in Washington during 1999.

West Virginia - Concerned that federal legislation on retail wheeling may preempt state action; West Virginia regulators are seeking to develop a consensus plan for restructuring the state's electric industry by the end of 1999. The Public Service Commission is pressing a special task force to develop a restructuring plan this spring or summer that all major stakeholders can agree to.

To add urgency to the matter, the PSC said it would hold "evidentiary hearings" on restructuring on August 17 and 24, 1999. The first hearing will involve power-supply reliability, universal service and consumer protection issues; the second will address rate stability and the valuation of utility generation assets.

Last spring, the PSC formed the task force after the West Virginia state legislature designated the commission as "the appropriate agency" to determine whether retail competition is in the public interest.

The task force met through the rest of 1998, but failed to agree on a number of key "threshold points," including the timing and duration of the transition period; the means for providing both revenue stability for utilities and rate stability for retail customers; and the issue of whether utilities should be forced to divest their generation assets.

West Virginia's two largest investor-owned utilities – American Electric Power and Allegheny Energy – and large energy users continue to support relatively quick implementation of retail wheeling.

But the state's Consumer Advocate Division has argued that electric rates in West Virginia are low, and would likely rise for residential customers under customer choice.

The PSC noted in announcing the August 1999 hearings that restructuring laws approved in several other states have included 'at least some" of the following provisions: multi-year rate caps to provide rate stability during a transition to fully open competition; a stranded-cost-recovery mechanism; mandated plant divestment; and guaranteed help for lower-income electric customers.

Finally, the commission said a study by West Virginia University researchers found that restructuring of the state's electric industry could increase the average capacity factor of power plants there to 70% from 64% now. That increase plant use, the study said, could add a total of some 1,300 new jobs, including 280 in the coal industry.

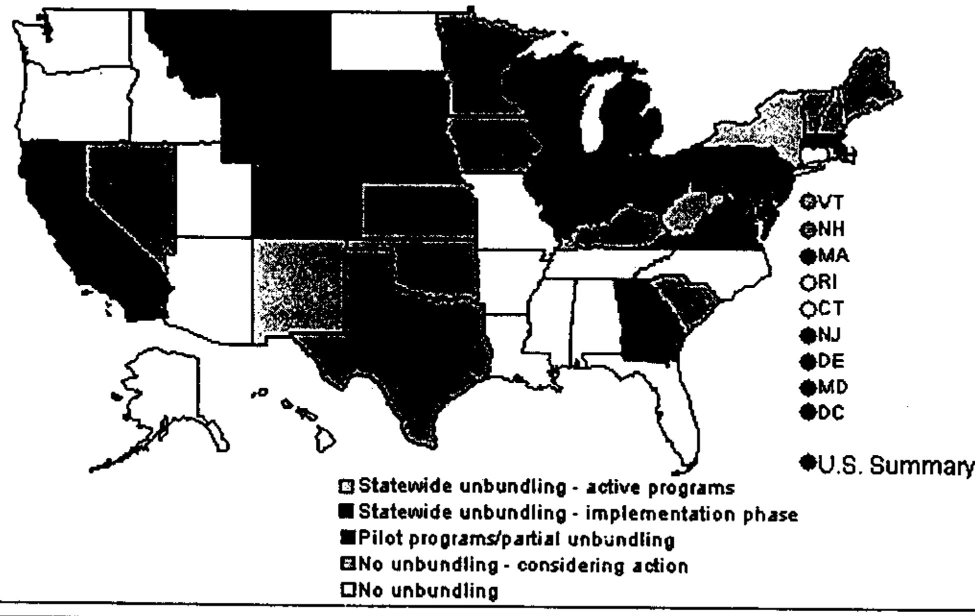
Wisconsin - Transmission constraints in the region have caused the Wisconsin Public Service Commission (PSC) to focus its efforts on the development of an Independent System Operator (ISO) for the region.

Wisconsin Electric Power, Wisconsin Public Power, Inc. and Commonwealth Edison joined the Midwest ISO (MISO) but the PSC previously concluded that the Midwest ISO was deficient based on commission principles.

The Federal Energy Regulatory Commission has not yet issued a final order on the Midwest ISO and the PSC's position on Wisconsin utilities joining the MISO is unknown.

Wyoming - There has been no significant electric industry restructuring activities by either the Wyoming legislature or Public Service Commission in the past twelve months.

Status of Natural Gas Residential Choice Programs By State as of July 1999



Residential Natural Gas Restructuring Status	States
Statewide unbundling - active programs	NM, NY, WV
Statewide unbundling - implementation phase	CA, CO, GA, MD, MA, NJ, OH, PA
Pilot programs/partial unbundling	DC, DE, IL, IN, MI, MT, NE, SD, VA, WI, WY
No unbundling - considering action	IA, KS, KY, ME, MN, NV, NH, OK, SC, TX, VT
No unbundling	AK, AL, AR, AZ, CT, FL, HI, ID, LA, MS, MO, NC, ND, OR, RI, TN, UT, WA
United States Summary	

This site provides an overview of the status of natural gas industry restructuring in each state, focusing on the residential customer class. Retail unbundling, or restructuring, is the division of those services required to supply natural gas to consumers into various components that can then be separately purchased. With complete unbundling, consumers can choose their own gas supplier and the LDC still provides local transportation and distribution services. The various unbundling programs are often called "customer choice" programs.

The site also includes the most recent (1997) EIA annual price and consumption data for the residential and commercial sectors and average city gate prices. When possible, these data are compared with information obtained from the state public utility commissions or local distribution companies (LDCs) to provide information on the level of participation in the customer choice programs. More detailed information about the various state programs will be added at a later date.

APPENDIX 5: COMPREHENSIVE ELECTRICITY RESTRUCTURING BILLS--1999

ISSUE	H.R. 667—Burr (2/99)	H.R. 1587—Stearns (4/99)	S. 1047—Murkowski H.R. 1828—Bliley Administration/DOE (5/99)	S. 516—Thomas (3/99)	H.R. 2050—Largent/Markey (6/99)
Jurisdiction	Clarifies states' ability to require open access; preserves state authority to impose charges to support public benefit programs and stranded cost recovery.	FERC authority over unbundled retail transmission; clarifies states' ability to require open access; preserves state authority over stranded costs and ability to impose charges to support public benefits.	FERC jurisdiction over unbundled retail transmission; states have authority over stranded costs except where a state "lacks such authority."	FERC jurisdiction over unbundled retail transmission; states determine retail electric policies; states have jurisdiction to regulate any retail electric supply or any local distribution service provided to an ultimate customer; preserves state authority over stranded costs and ability to impose charges to support public benefit programs.	FERC jurisdiction over unbundled retail transmission; state authority over stranded costs.
Reliability	Nothing prohibits states' ability to impose charges to ensure and enhance reliability of retail electric service.	Consent of Congress given to formation and operation of a Reliability Council that makes recommendations to FERC. Retains state authority regarding safety and reliability of electric utility or local distribution company facilities.	FERC required to approve the formation and oversight of an Electric Reliability organization to prescribe and enforce mandatory reliability standards; establishes a DOE board to investigate major bulk-power system failure.	Enables states to establish and enforce any performance standards for retail sales to ensure system reliability; provides for state regional advisory role; establishes an electric reliability organization subject to FERC oversight.	FERC required to approve the formation and oversight of an electric reliability organization to prescribe and enforce mandatory reliability standards.

ISSUE	H.R. 667—Burr (2/99)	H.R. 1587—Stearns (4/99)	S. 1047—Murkowski H.R. 1828—Bliley Administration/DOE (5/99)	S. 516—Thomas (3/99)	H.R. 2050—Largent/Markey (6/99)
Transmission Organizations	No provision	Encourages the creation of ISOs; nothing affects FERC authority to order creation of ISOs.	Grants FERC authority to establish an entity for independent operation, planning and control of interconnected transmission facilities and require utilities to relinquish control over transmission facilities to an ISO.	No provision	Grants FERC authority to oversee creation of regional transmission organizations and compel utilities to turn over control of transmission to such an entity.
Public Benefits	Preserves states' authority to impose charges to support universal service and public benefit programs.	Preserves states' authority to impose charges to support universal service and public benefit programs.	Creates a $3 billion "Public Benefits Fund" for low-income assistance, efficiency programs, consumer education and emerging technologies, funded by a transmission fee.	Preserves states' authority to impose charges to support universal service and public benefit programs.	Preserves states' authority to impose charges to support universal service and public benefit programs. FERC and states should ensure that competition does not result in disadvantages to rural or low-income customers.

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Consumers' Rights	No provision	No provision	Suppliers must provide information regarding prices, terms and conditions and generation sources and emissions. DOE is authorized to establish database to help consumers compare suppliers. Cramming and slamming are prohibited.	States may impose protections against unfair business practices.	Suppliers must provide information regarding prices, terms and conditions and generation sources and emissions. Cramming and slamming are prohibited.
Renewables and Environmental	Preserves states' rights to impose charges to encourage programs for the environment, renewable energy, energy efficiency and conservation.	Preserves states' rights to impose charges to encourage programs for the environment, renewable energy, energy efficiency and conservation.	Creates renewable portfolio system mandating that sellers must obtain specified percentages of generation from non-hydroelectric renewable technology (7.5% by 2010). Those unable to meet the standard could buy credits from the DOE or other generators. RPS sunsets in 2015.	No provision	If renewables count for less than 3% of generation by 2005, renewable portfolio system goes into effect. Each seller will be required to use renewables for 3% of its total generation. Those unable to meet the standard could buy credits from the DOE or other generators. RPS sunsets in 2015.
"Grandfathering"	No provision	No provision	No provision	No provision	Limited grandfathering to all states enacting legislation by 1/1/2001

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PUHCA	Repeals PUHCA 12 months after date of enactment.	Repeals PUHCA 12 months after date of enactment.	Repeals PUHCA 18 months after date of enactment.	Repeals PUHCA 18 months after date of enactment	Holding companies exempted from PUHCA 18 months after enactment unless they provide retail service in two or more closed states.
PURPA	PURPA mandatory purchase provisions repealed; existing contracts honored; FERC to assure recovery of PURPA-related stranded costs.	PURPA mandatory purchase provisions repealed; existing rights and remedies not affected; FERC to assure recovery of PURPA-related stranded costs.	PURPA mandatory purchase provisions repealed; existing contracts honored.	PURPA mandatory purchase provisions repealed; existing contracts honored.	PURPA mandatory purchase provisions repealed; existing rights and remedies not affected; FERC to assure recovery of PURPA-related stranded costs.
Market Power	No provision	No provision	Authorizes FERC, upon petition by a state, to require generators to submit a plan mitigating market power. FERC may accept or modify the plan; modification may include divestiture.	No provision	Authorizes FERC to require generators to submit a plan mitigating market power. If FERC determines plan is insufficient, FERC may order cost-based rates for wholesale or retail sales, or require a utility to turn over transmission to an RTO.
FERC Transmission Authority	No provision	FERC open access rules apply to municipals and cooperatives, TVA and PMAs.	FERC open access rules apply to municipals and cooperatives, TVA and PMAs.	FERC open access rules apply to municipals and cooperatives, TVA and PMAs.	FERC open access rules apply to municipals and cooperatives, TVA and PMAs.

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"Date certain" mandate	No provision	No provision	Mandates open access 1/1/2003, although states may opt out before that date.	Left to discretion of states.	Mandates open access 1/1/2002, although states may opt out before that date.
Stranded costs	States have ability to impose charges to recover stranded costs. If a state receives federal energy assistance, the state must file any provisions for stranded cost recovery with the FERC, and may not change these provisions for 7 years.	Retail stranded costs left to states; states may impose a charge for stranded cost recovery.	States determine the amount of recoverable stranded costs; FERC given back-up authority if state lacks authority.	Retail stranded cost decisions left to states.	States determine the amount of stranded costs, and may impose a non-bypassable charge to recover stranded costs.
Reciprocity	States with retail competition may permit an electric utility to deny transmission access to an out-of-state monopoly utility for the purpose of selling directly to retail customers.	States may order local utilities to provide open access to facilities only for sales from utilities in states that also have open access.	Permits a state regulatory authority to prohibit sales of electricity from a distribution utility that does not allow retail open access to customers of utilities with open access.	States may establish that a utility may not provide open access unless those utilities themselves are subject to comparable open access conditions.	Provides states with open access the authority to preclude an out-of-state utility with a retail monopoly from selling in that state, unless that utility permits customer choice.